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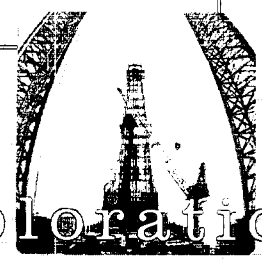
Spinnaker continues to build and explore its inventory of prospects in shallow water depths as it transitions to greater investment in the deep waters of the Gulf of Mexico. The Company's exploratory exposures generally seek meaningful new sources of oil and gas.



Spinnaker Exploration

2002 ANNUAL REPORT

CORPORATE PROFILE > Spinnaker Exploration Company ("Spinnaker" or the "Company") is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. Gulf of Mexico. Formed in December 1996 by Spinnaker's Chief Executive Officer, Warburg, Pincus Ventures, L.P. and Petroleum Geo-Services ASA, Spinnaker became a publicly traded company in September 1999.

Spinnaker's business model focuses on information and technology. The Company has license rights to approximately 14,000 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 40 million acres, which the Company believes is one of the largest 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. This emphasis on information and technology has translated into success for the Company. From its inception through December 31, 2002, Spinnaker participated in drilling 120 wells, 70 of which were successful. As of December 31, 2002, the Company had estimated proved reserves of 323.6 billion cubic feet of gas equivalent ("Bcfe"), approximately 44% of which was natural gas. The Company has significant operations on the shelf and is continuing to expand its presence in the deep waters of the Gulf of Mexico.

The Company is headquartered in Houston, Texas. Spinnaker's common shares are traded on the New York Stock Exchange under the symbol "SKE."

SPINNAKER EXPLORATION COMPANY

Financial Highlights

(thousands of dollars except per share amounts)

For the Year Ended December 31,	2002	2001	2000
Revenues	$ 188,326	$ 210,376	$ 121,383
Income from operations	49,090	100,285	57,264
Net income	31,579	66,226	38,566
Net income per common share - basic	1.00	2.45	1.70
Net income per common share - diluted	0.97	2.34	1.61
Cash flow from operations:			
Net income	31,579	66,226	38,566
Depreciation, depletion and amortization	109,912	85,457	47,760
Deferred income tax expense	18,063	36,977	20,833
Other	881	549	306
	160,435	189,209	107,465
Cash flow from operations per common share	4.91	6.67	4.48
Capital costs incurred	342,479	302,520	194,016

As of December 31,	2002	2001	2000
Cash and cash equivalents	$ 32,543	$ 14,061	$ 63,910
Short-term investments	–	–	22,387
Property and equipment, net	760,854	522,573	304,381
Total assets	842,715	587,316	442,704
Equity	692,977	458,492	361,259

SPINNAKER EXPLORATION COMPANY

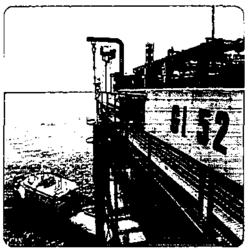
Operating Highlights

	2002	2001	2000
Production (MMcfe)	51,419	53,094	30,194
Percent natural gas production	88%	96%	96%
Average natural gas sales price per Mcf [1]	$ 3.56	$ 3.96	$ 4.03
Average oil and condensate sales price per barrel [1]	$ 26.39	$ 24.90	$ 22.98
Proved reserves (MMcfe)	323,577	323,132	182,688
Percent proved natural gas reserves	44%	54%	90%
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands) [2]	$ 847,273	$ 415,139	$ 1,320,672
Lease acreage (net acres, in thousands)	742	629	337
3-D seismic data coverage (millions of acres)	40	39	39

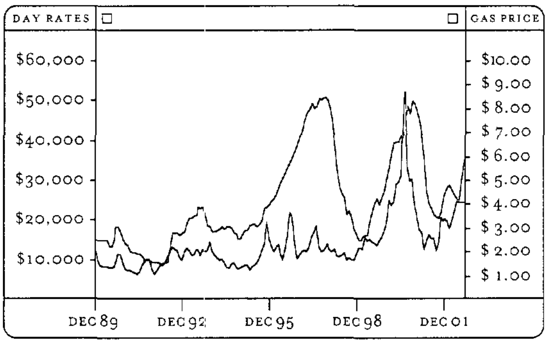
[1] Including the effects of hedging activities

[2] Calculated using prices of $4.91, $2.71 and $9.99 per Mcf of natural gas and $30.50, $19.23 and $30.41 per barrel of oil as of December 31, 2002, 2001 and 2000, respectively

The current environment of high commodity price and controlled service costs favors companies with large assembled prospect inventories. Spinnaker's inventory of 120+ prospects is well balanced between shallow and deep waters as well as oil and natural gas.



JACK-UP DAYRATES AND NATURAL GAS PRICES



SOURCE: Analysts Research, January 2003

To Our Shareholders,

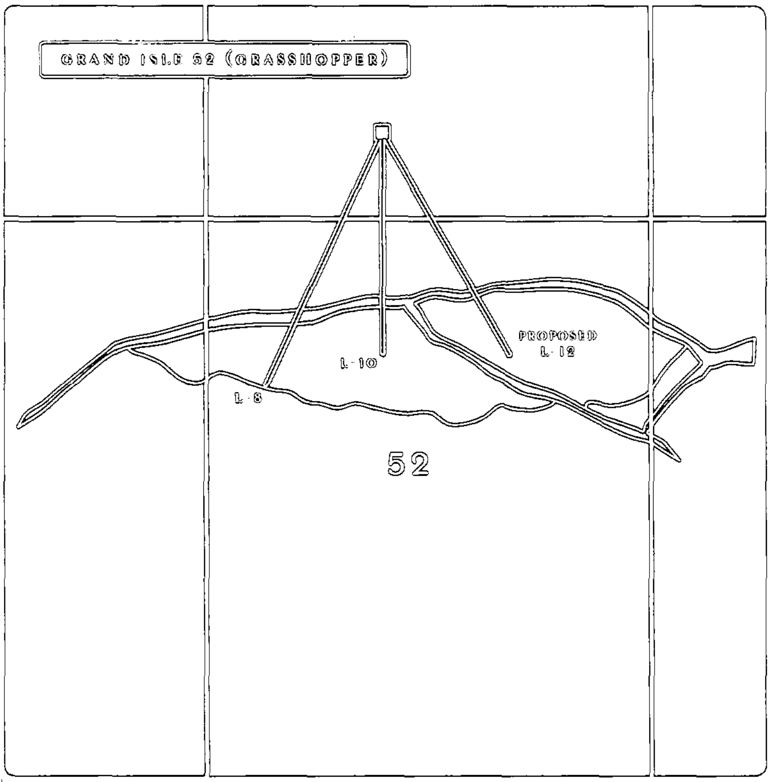
In past years, I have had the enviable task of reporting excellent results from Spinnaker's operations. Spinnaker continues to be a solid and exciting Company. The past year, however, has presented more challenges and fewer large successes than we expected. The exploration business can be humbling.

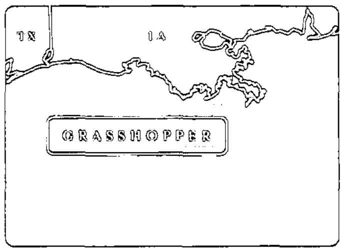
This fluctuation in operating and financial results shouldn't surprise us; exploration is a statistical process by nature. The good news is that the design of the Company considered that our results would fluctuate and now provides the advantage – continuity in our efforts. We have a large 3-D seismic database, a dynamic and high quality prospect inventory, four large and visible field developments in progress, a great balance sheet and talented people to successfully execute our strategies. Our growth prospects for the medium and longer term are very good.

The transition from a shallow water explorer and producer to a company with a balanced portfolio of shallow and deepwater activities is well underway. Our prospect inventory and capital is allocated almost equally to the two plays now and by mid-2004 our production and cash flow should be as well. When this transition is complete, Spinnaker will stand as the best example yet of a smaller Gulf of Mexico company diversifying into the deep water without experiencing large liquidity issues.

Although we relied on the same basic process that brought success in prior years, we had a tough exploration year and it showed up in production, reserves and a higher cost structure, primarily as a result of higher depreciation, depletion and amortization rates. Spinnaker earned $0.97 per diluted common share and generated per share cash flow of $4.91. Oil and gas production declined modestly from 2001 to 2002 and estimated reserves of oil and gas ended the year flat from levels of one year ago.

Although exploratory success rates stayed reasonably high at 54% in 2002 versus 58% inception to date, we did not find the number of larger shelf fields that have punctuated our past results. I suspect that





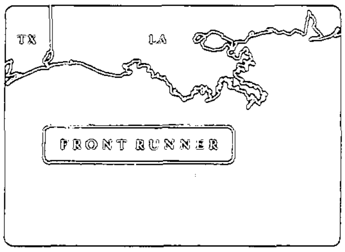
The Grasshopper Field could be a significant oil discovery on the shelf in which we participated during 2002. Two wells are currently producing approximately 8,000 barrels of oil equivalent per day, and we expect to drill a third well around mid-year. Spinnaker owns a 50% working interest in the Grasshopper Field.

there is no outcome in our business more commercial at this time than a large natural gas discovery situated in shallow water and capable of prolific producing rates. While the Resolute Field (High Island 197) was discovered in late 2001, Spinnaker drilled three additional wells in 2002. Two of those wells extended the field and the third well found the Resolute South Field. Spinnaker built production facilities and brought the field online during 2002, eight months after the initial discovery. More drilling in the Resolute area is possible during 2003. We may have found another significant shelf field during 2002 in the Grand Isle Addition, but more drilling is necessary to assess its size.

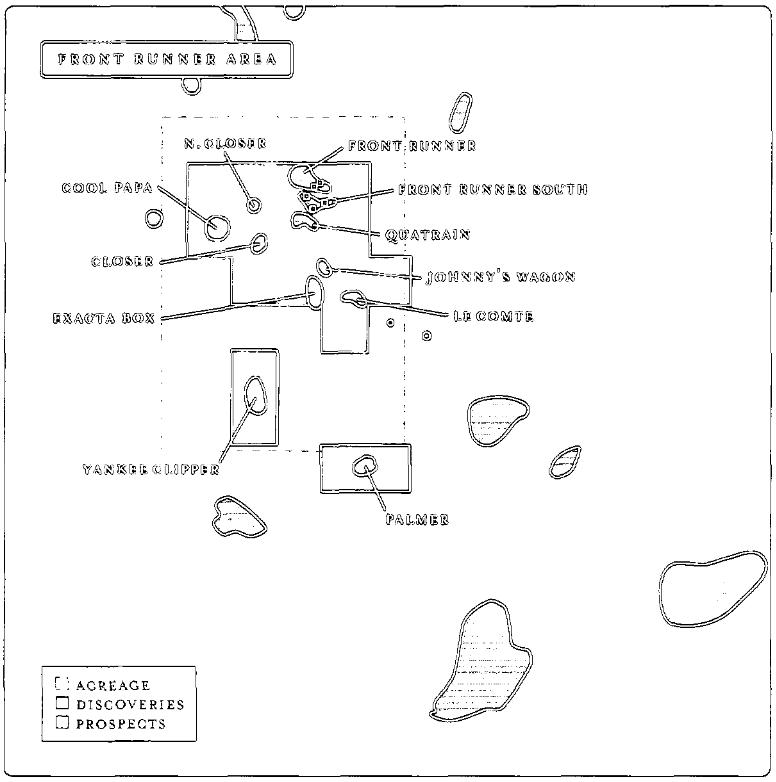
We will continue to focus a meaningful portion of our efforts toward shelf exploration. In fact, during 2003 we're likely to increase our holdings that are prospective for the deep stratigraphic section or the so-called Deep Shelf play. Spinnaker is a technical leader in this large, under-explored play and we should continue to have success with it.

The Company's position on the shelf is enviable. Spinnaker has drilled or participated in drilling wells that opened or enhanced in a meaningful way four new geologic plays in that deep section of sediments. We currently own an inventory of about 60 prospects on the shelf and hold an interest in 627,000 gross acres (436,000 net acres) in the play. Most of this acreage was acquired for its deep exploratory potential. We have numerous leads and prospects in which we have no current ownership, as well.

Through the process of having drilled or participated in 65 or so deep wells on the shelf, we have acquired considerable engineering and operating expertise. These wells are not easy to drill and these fields, due to extraordinarily high pressure and temperature conditions, are somewhat unique. Very high production rates are not uncommon. The Company owns an interest in a single well that produces 115–120 million cubic feet of gas equivalent per day ("MMcfged") and a number of wells that have produced, or are producing, 25–40 MMcfged. At $4.00 to $6.00 per thousand cubic feet of gas ("Mcf"), the impact of these prolific wells can be substantial. While finding and development costs in this play will most likely average $2.00 per Mcf or more, the demand for these new natural gas supplies is high.



The Front Runner area continues to be one of the most exciting exploratory areas in the deep waters of the Gulf of Mexico. During 2002, we sanctioned the Front Runner project, successfully tested the Quatrain prospect and commenced construction on the Spar production facility. Initial production from this area is expected in the summer of 2004. We have identified at least ten undrilled prospects in the Front Runner area.



The economics of prospects in these shallow waters benefit disproportionately from the robust gas markets. The decline of the conventional natural gas plays on the shelf, which historically have provided 15%–20% of total U.S. gas supply, is a major reason for the high natural gas prices that exist today. Assuming that demand for natural gas stays flat, reduced supplies will likely keep prices attractive for some time. As a result of these fundamentals, great volatility has become a familiar feature of the natural gas markets. Prolific new supplies from shallow waters, which can be developed and produced in short cycle times and thus benefit from this pricing volatility, will come almost exclusively from this Deep Shelf play in the future. The potential rewards are large for the successful explorer. Spinnaker is well situated and there are exciting things to come for the Company on the shelf.

As for longer term growth, the deep water of the Gulf of Mexico is an important focus of Spinnaker's strategy.

Spinnaker holds approximately 128 blocks (727,000 gross acres, or 299,000 net acres) in the deep waters of the Gulf of Mexico. Our captured inventory totals approximately 65 prospects. We began accumulating this position in 1997, but most of these leases and prospects relate to our efforts since 2000. In fact, Spinnaker increased its net acreage position by 50%, or approximately 100,000 net acres, in deep water during 2002 alone. The Company's results from the play are noteworthy as well. To date, the Company has discovered hydrocarbons in ten new deepwater fields. Two have produced or are currently producing, four are in development and four await more information, evaluation, additional drilling or an infrastructure decision. We have been successful in finding hydrocarbons in about 60% of our deepwater efforts.

Spinnaker and its partners made considerable exploration/exploitation progress during 2002 in the Front Runner area. Construction of the related production facilities also progressed substantially this past year.

In the project area during 2002, the Front Runner South Field was delineated with four successful wells and sidetracks. True vertical depth pay thickness averaged 490 feet in those wells. The Front Runner

Since our inception in 1996, Spinnaker's success has been technology driven and has focused on our 3-D seismic data in the Gulf of Mexico. During 2002, we added 2,200 blocks, or 17,200 square miles of 3-D seismic data, bringing our seismic database to approximately 14,000 blocks covering approximately 40 million acres.

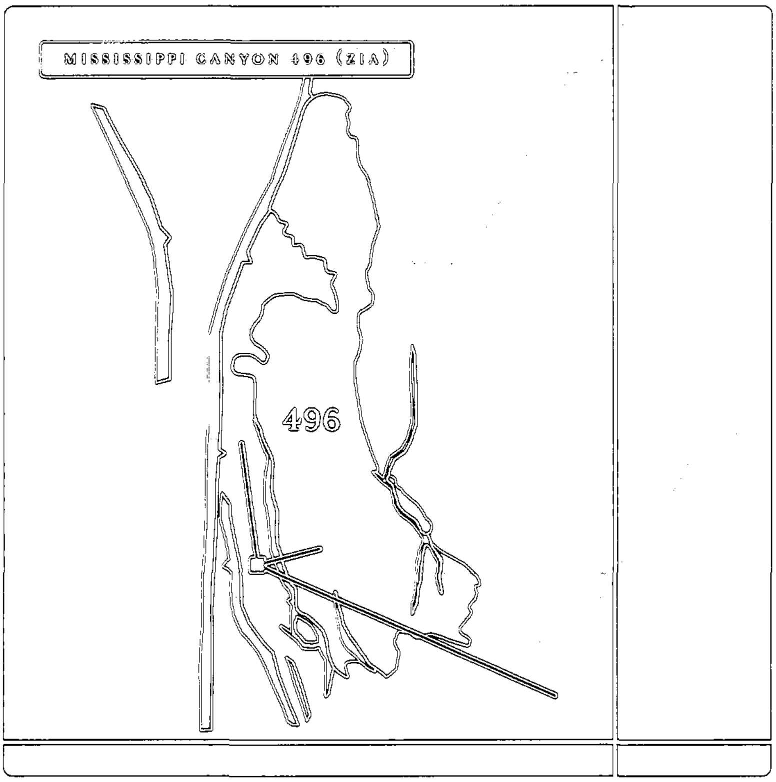
partners sanctioned development of the fields during the first quarter of 2002. Also during the year, another well was drilled in the main Front Runner Field and a third consecutive discovery was made in the basin by Spinnaker and its partners at the Quatrain prospect (Green Canyon 382). Quatrain was drilled as a deviated exploratory test from the same surface location as the Front Runner and Front Runner South wells and can therefore be produced through the production Spar that is now under construction. The Front Runner Spar production facility is scheduled to be operational by mid-year 2004.

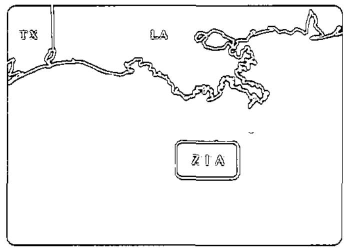
When the Front Runner project is completed and including well and export pipeline costs, the partners will have spent in excess of $660 million, or $165 million net to Spinnaker. This has required a considerable focus from our organization and a meaningful portion of our balance sheet. It should also prove to be an outstanding investment.

At the Front Runner facility's peak projected producing rate of 60,000 barrels of oil per day ("BOPD") and 110 million cubic feet of gas per day, Spinnaker's net production will be approximately 20,000 barrels of oil equivalent per day, or 120 MMcfged. That is the equivalent of approximately 85% of our average daily producing rate of 141 MMcfged during 2002. Besides the obvious initial impact of the project, we believe that future exploration and exploitation of the Front Runner area fields will likely keep production constant for several years to come. Front Runner should become a legacy asset in our portfolio of properties and will alter our basic decline rates as a Company. It shouldn't be overlooked that the development of this substantial asset has been accomplished without degradation of Spinnaker's balance sheet.

Spinnaker also holds interest in about 100,000 acres in the immediate vicinity of the Front Runner area fields and will participate in new exploratory drilling during 2003. With an inventory of ten undrilled prospects in the area, we are hopeful of additional success.

Front Runner is certainly our largest deepwater success to date. However, the Company achieved other milestones during the year as well.





Development of our deepwater Zia Field has progressed substantially. It is anticipated that Zia will commence production in the third quarter of 2003. Zia is one of six deepwater fields involving Spinnaker that has either commenced production or that is currently in development. The Company owns a 35% working interest in the Zia Field.

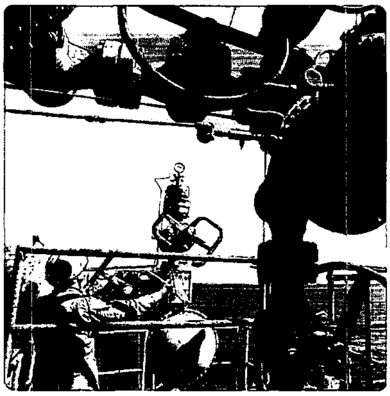
In August 2002, the Zia project (Mississippi Canyon 496) was sanctioned for development by Spinnaker and its operating partner. The project is situated in approximately 1,800 feet of water and will feature a dual flow line tie-back to an existing field 16 miles away. The project should commence production at a rate of 7,500–9,000 BOPD during the third quarter of 2003. Depending on production performance, a second well could be drilled and the project has been designed to accommodate this possibility with minimum incremental cost.

Spinnaker also operated its first development in deep water during 2002. The Sangria project (Green Canyon 177) commenced production during June 2002 through a 6.9 mile subsea tie-back to the Salsa platform. The project went from sanction to production in approximately six months. This project success was the direct result of high quality additions to Spinnaker's very capable staff and builds our confidence about the challenges that we face in transitioning to deep water. People do make the difference and Spinnaker's staff is arguably one of the very best in the industry.

The fundamental drivers of the Company's future; i.e., its technical prowess and its information resources, continued to grow this past year. During 2002, we added approximately 2,200 blocks (5,000 acres per block), or 17,200 square miles of 3-D seismic information acquired in the Gulf of Mexico. Our database is now almost 14,000 blocks, or about 109,000 square miles. Almost two-thirds of the basic time data to which we hold license has had some processing upgrade and most of this data will see more enhancement in the future. A fair amount of that upgrading has been conducted through Spinnaker's internal processing facilities and that trend will continue in the future.

The Company has expanded its data management and processing capabilities and now stores 62 terabytes of information on its systems. Spinnaker has the internal capability to output both pre-stack time and pre-stack depth products. We also increasingly search the seismic data for attributes that might enhance our geologic understanding of a prospect or that may illuminate a given technical risk with greater clarity. In order to better apply and digest this huge volume of information, we have built an

Spinnaker has become a leader in Gulf of Mexico exploration by building a quality and diverse inventory of prospects while maintaining a solid balance sheet. This mix is necessary to persevere through economic and commodity cycle downturns.



advanced visualization center in our offices. We believe that we are the smallest exploration and production company with this capability. The visualization center also allows us to involve all disciplines in the process: geophysical, geological, engineering, land, permitting, finance/accounting and management. We believe that this willingness to embrace and invest in these enabling technologies represents the future for the independent explorer/producer.

It may sound as though we should never drill a dry hole or at least that this should be our goal. Nothing could be further from the truth. We will continue to assume risk in order to create real value – there are no free rides. This is the dilemma for not only the explorer, but also the investor. One needs only to view in context the forward pricing curves for natural gas and oil versus offshore rig utilization to understand that inadequate prospect inventory exists in the Gulf of Mexico and other domestic plays. If there was an abundant, quality prospect inventory, there would also be abundant natural gas supplies at low cost. The industry is struggling to replace the exploratory inventory that has been consumed during the favorable pricing environment that has existed since the mid-1990s. The realities of higher depletion rates and lower per well reserves apply themselves to Canada, as well. The question then becomes "Who is likely to create and benefit through exploration inventory?" We believe that one answer to that question continues to be Spinnaker.

As always, we are deeply grateful for your interest and support of our Company.

R. Jarvis

ROGER L. JARVIS
CHAIRMAN OF THE BOARD, PRESIDENT AND CHIEF EXECUTIVE OFFICER

Financial Review

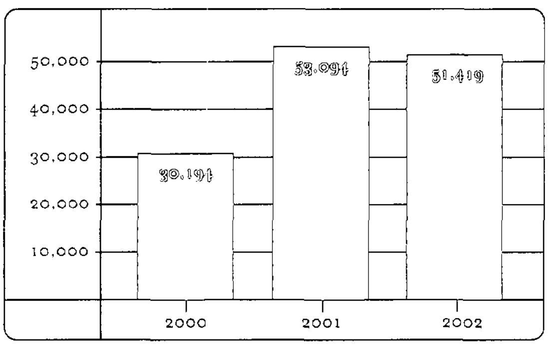
Net income in 2002 was $31.6 million, or $0.97 per diluted common share, compared to 2001 net income of $66.2 million, or $2.34 per diluted common share. Cash flow from operations in 2002 was $160.4 million, or $4.91 per diluted common share, compared to 2001 cash flow from operations of $189.2 million, or $6.67 per diluted common share.

Revenues in 2002 were $188.3 million compared to revenues of $210.4 million in 2001. Of the $22.1 million net decrease in revenues, $29.4 million was due to a lower average commodity price on an equivalent basis and $6.9 million related to decreased production, offset in part by an increase in net hedging income of $14.2 million.

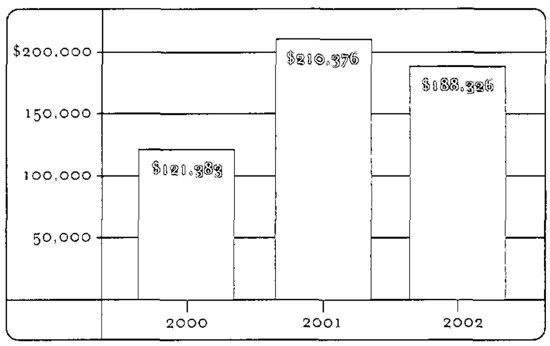
Production in 2002 decreased to 51.4 Bcfe from 53.1 Bcfe in 2001. Realized prices in 2002 averaged $3.56 per Mcf and $26.39 per Bbl compared to $3.96 per Mcf and $24.90 per Bbl in the same period in 2001, representing a decrease of 8% on an equivalent basis. The realized average natural gas price in 2002 was positively impacted by $0.10 per Mcf related to hedging activities. Excluding the effects of hedging activities, the natural gas price averaged $3.46 per Mcf in 2002 compared to an average price of $4.14 per Mcf in 2001, representing a decrease of 16% on an equivalent basis.

Spinnaker ended 2002 with no debt and cash and cash equivalents of $32.5 million. Looking forward, although we anticipate carrying some debt in 2003, we plan to sustain a balanced, diversified exploration effort as we continue our transition to the deep waters of the Gulf of Mexico.

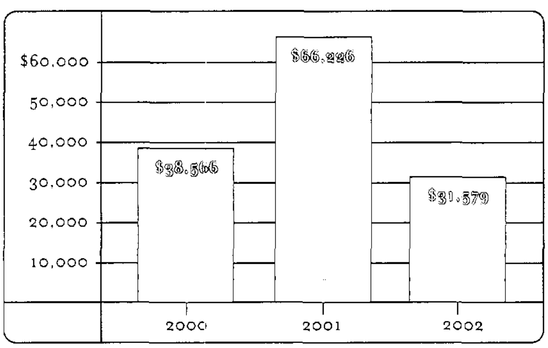
PRODUCTION (MMcfe)



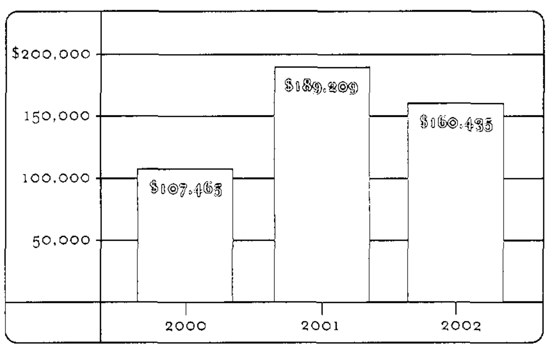
REVENUES (in thousands)



NET INCOME (in thousands)



CASH FLOW FROM OPERATIONS (in thousands)



Cautionary Statement About Forward-Looking Statements

Some of the information in this annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). The forward-looking statements speak only as of the date made, and the Company undertakes no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events. These future events include the following matters:

- financial position;
- business strategy;
- budgets;
- amount, nature and timing of capital expenditures, including future development costs;
- drilling of wells;
- natural gas and oil reserves;
- timing and amount of future production of natural gas and oil;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development and property acquisitions; and
- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect the Company's operating results, including:

- the risks associated with exploration;
- delays in anticipated start-up dates;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization rate;
- production and reserves concentrated in a small number of properties;
- operating hazards attendant to the natural gas and oil business;
- drilling and completion risks, which costs are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- impact of weather conditions on timing and costs of operations;
- availability and cost of material and equipment;
- actions or inactions of third-party operators of the Company's properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

Any of the factors listed above and other factors contained in this annual report could cause the Company's actual results to differ materially from the results implied by these or any other forward-looking statements made by the Company or on its behalf. The Company cannot provide assurance that future results will meet its expectations. You should pay particular attention to the risk factors and cautionary statements described under "Risk Factors" in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

Financial and operating results in 2002 compared to 2001 included:

- Revenues of \$188.3 million, down 10%.
- Income from operations of \$49.1 million, down 51%.
- Net income of \$31.6 million, or \$0.97 per diluted share, down 52%.
- Production of 51.4 Bcfe, down 3%.
- Proved reserves of 323.6 Bcfe, reserve replacement was 101% of production in 2002.

Spinnaker's results of operations and financial position were significantly impacted by lower commodity prices and production in 2002. Of the \$22.1 million net decrease in revenues, \$29.4 million was due to a lower average commodity price on an equivalent basis and \$6.9 million related to decreased production, offset in part by an increase in net hedging income of \$14.2 million. The Company had \$32.5 million in cash and cash equivalents and no debt at December 31, 2002.

RISK FACTORS

In addition to the other information set forth elsewhere in this annual report, the following factors should be carefully considered when evaluating Spinnaker.

Exploration is a high-risk activity, and the 3-D seismic data and other advanced technologies the Company uses cannot eliminate exploration risk and require experienced technical personnel whom the Company may be unable to attract or retain.

The Company's future success will depend on the success of its exploratory drilling program. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. In addition, the Company often is uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of the additional exploration time and expense associated with a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or equipment.

Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. The Company could incur losses as a result of expenditures on unsuccessful wells. Poor results from exploration activities could materially and adversely affect future cash flows and results of operations.

The Company's exploratory drilling success will depend, in part, on its ability to attract and retain experienced explorationists and other professional personnel. Competition for explorationists and engineers with experience in the Gulf of Mexico is extremely intense. If the Company cannot retain its current personnel or attract additional experienced personnel, its ability to compete in the Gulf of Mexico could be adversely affected.

A substantial portion of Spinnaker's proved reserves are associated with its deepwater oil discovery at Front Runner. The development of Front Runner will require significant financial resources before initial production and remains subject to other uncertainties that could have a material impact on the development of this discovery.

Spinnaker's deepwater oil discovery at Front Runner, in which the Company has a 25% non-operator working interest, has required and will continue to require significant financial resources in advance of the expected initial production date in the summer of 2004. The Company has incurred \$70.2 million in capital expenditures for Front Runner through December 31, 2002 and expects to incur an aggregate of approximately $67.0 million in future development costs during 2003 and 2004. Because another oil and gas exploration and production company operates Front Runner, the Company has a limited ability to influence the operations and costs associated with this property.

Front Runner is located in approximately 3,500 feet of water and wells have been drilled in the Front Runner area to total depths in excess of 20,000 feet. The Company has limited experience with large deepwater and deep drilling depth discoveries similar to Front Runner as most of its prior discoveries have occurred in shallower waters and at shallower drilling depths. As a result of these uncertainties and risks, the Company may encounter difficulties and delays that could cause actual expenditures to exceed anticipated amounts.

J. Ray McDermott Inc. ("McDermott"), the contractor responsible for construction, delivery and installation of the Front Runner spar production facility, has announced that it is experiencing liquidity concerns. If McDermott experiences additional significant unanticipated costs in the future, it may be unable to fund all of its anticipated operating and capital needs, which may delay the expected delivery date of the spar production facility as well as the initial production date and actual expenditures may exceed anticipated amounts.

The hull of the spar production facility is being constructed in Dubai, U.A.E. Due to the current military conflict in the Middle East, the delivery date of the hull to the Gulf of Mexico may be delayed. Additionally, weather and other conditions may delay the installation of the spar production facility on location. Any delays in the delivery or installation dates would cause a delay in the initial production date.

Front Runner accounted for more than 60% of Spinnaker's proved undeveloped reserves at December 31, 2002. If the actual reserves associated with Front Runner are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

When production ultimately commences for this discovery, it may produce substantially less oil and natural gas than currently projected. Additionally, the Company cannot predict commodity prices when production commences. If production is substantially less than currently projected or commodity prices are low, the Company's results of operations and financial condition could be adversely affected.

These uncertainties and other risks described in this "Risk Factors" section and elsewhere in this annual report make it difficult to predict whether Front Runner can be successfully or economically developed. If Front Runner cannot be successfully and economically developed, the Company's future business, financial condition and operating results will be materially and adversely affected.

The natural gas and oil business involves many operating risks that can cause substantial losses.

The natural gas and oil business involves a variety of operating risks, including fires, explosions, blowouts and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of the Company's operations and repairs to resume operations. If the Company experiences any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect its ability to conduct operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company's operations.

Exploration for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico involves greater operational and financial risks than exploration at shallower depths and in shallower waters. These risks could result in substantial losses.

The Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico where operations are more difficult and costly than at shallower depths and in shallower waters. Deep depth and deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. The Company has experienced and will continue to experience significantly higher drilling costs for its deep depth and deepwater prospects.

At December 31, 2002, approximately 92% of the Company's proved undeveloped reserves were located in deep water. The deep water lacks the physical and oilfield service infrastructure present in the shallower waters. As a result, deepwater projects require long-term commitments of significant financial resources. Deepwater operations may also require a significant amount of time between the discovery date and the initial production date when the Company can market the natural gas or oil, increasing both the financial and operational risk involved with these operations.

The Company is vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico because it currently explores and produces exclusively in that area.

The Company's operations and revenues are impacted acutely by conditions in the Gulf of Mexico because it currently explores and produces exclusively in that area. This concentration of activity makes the Company more vulnerable than many of its competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

A significant part of the value of the Company's production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact the Company's business.

During 2002, approximately 44% of the Company's production came from three of its properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, the Company's cash flow would be adversely affected. In addition, at December 31, 2002, the Company's proved reserves were located on 26 different blocks in the Gulf of Mexico, with approximately 73% of the proved reserves attributable to six of these properties. One property, Front Runner, accounted for more than 60% of total proved undeveloped reserves and more than 40% of total proved reserves. If the actual reserves associated with any one of these six properties are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

The Commission is currently reviewing information from Spinnaker and other oil and gas companies operating in the Gulf of Mexico to assess how the industry is determining proved reserves related to new discoveries. Rules and regulations of the Commission allow companies to recognize proved reserves if economic producibility is supported by either actual production or a conclusive formation test. The Commission believes that a production flow test of reserves satisfies the requirements of a conclusive formation test. In the absence of a production flow test, compelling technical data must exist to recognize proved reserves. The industry has increasingly depended on advanced technical testing to support economic producibility. Spinnaker has recorded most of its proved reserves in deep water based on various advanced technical tests rather than production flow tests. The Company expects initial production from the majority of its proved undeveloped reserves in deep water to commence no later than the summer of 2004. The Company believes these proved reserves are properly recorded and classified. Spinnaker has furnished the information requested by the Commission and is unable to predict the outcome of the Commission's review of Spinnaker's and the industry's practices.

If any seismic contractor terminates its data agreement with Spinnaker, the Company's ability to find additional reserves could be impaired.

The Company's success depends heavily on its access to 3-D seismic data. If any seismic contractor terminates its data agreement with Spinnaker, the Company would lose access to a portion of its 3-D seismic data, which loss could have an adverse effect on its ability to find additional reserves. A seismic contractor may terminate its data agreement with Spinnaker on several grounds, including if a competitor of the seismic contractor acquires control of Spinnaker or if the Company breaches the data agreement with that seismic contractor, subject to certain exceptions.

Competitors may use superior technology which the Company may be unable to afford or which would require costly investments in order to compete.

The industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, the Company may be placed at a competitive disadvantage, and competitive pressures may force it to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company can. The Company cannot be certain that it will be able to implement technologies on a timely basis or at a cost that is acceptable to it. One or more of the technologies that the Company currently uses or that it may implement in the future may become obsolete, which may adversely affect the Company's results of operations and financial condition. For example, marine seismic acquisition technology has undergone rapid technological advancements in recent years and further significant technological developments could substantially impair the value of Spinnaker's 3-D seismic data.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or their underlying assumptions will materially affect the quantities and net present value of the Company's reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and net present value of reserves.

In order to prepare these estimates, the Company must project production rates and the timing of development expenditures. The Company must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from the Company's estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. Moreover, some of the producing wells included in the reserve report had produced for only a relatively short period of time as of December 31, 2002. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

It should not be assumed that the present value of future net cash flows from the Company's proved reserves is the current market value of its estimated natural gas and oil reserves. In accordance with Commission requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate.

The failure to replace reserves would adversely affect production and cash flows.

The Company's future natural gas and oil production depends on its success in finding or acquiring additional reserves. If the Company fails to replace reserves, its level of production and cash flows would be adversely impacted. In general, production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics and mechanical issues. The Company's total proved reserves decline as reserves are produced unless it conducts other successful exploration and development activities or acquires properties containing proved reserves, or both. The Company's ability to make the necessary capital investment to maintain or expand its asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. The Company may not be successful in exploring for, developing or acquiring additional reserves. If the Company is not successful, its future production and revenues will be adversely affected.

Relatively short production periods for Gulf of Mexico properties subject the Company to higher reserve replacement needs, require the Company to incur capital expenditures more frequently to replace production and may impair its ability to slow or shut-in production during periods of low prices for natural gas and oil.

Reservoirs in the Gulf of Mexico are generally sandstone reservoirs characterized by high porosity, permeability, pressure and temperature. Production of these reservoirs is generally constant for a relatively shorter period of time with a rapid decline in production at the end of the reservoir life compared to production of reservoirs in many other producing regions of the world. As a result, reserve replacement needs from new prospects in the Gulf of Mexico are greater and require the Company to incur capital expenditures more frequently to replace production than would typically be required in many other producing regions of the world. The Company expects a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and a shut-in for pipeline repairs.

Also, revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods. The Company's potential need to generate revenues to fund ongoing capital commitments or reduce future indebtedness may limit its ability to slow or shut-in production from producing wells in the future during periods of low prices for natural gas and oil.

Natural gas and oil prices fluctuate widely, and low prices could have a material adverse impact on the Company's business and financial results.

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. The amount the Company can borrow under the Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce.

Prices for natural gas and oil fluctuate widely. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in natural gas and oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions. If natural gas and oil prices decline, even if for only a short period of time, it is possible that write-downs of natural gas and oil properties could occur in the future.

Hedging production has limited and may continue to limit potential gains from increases in commodity prices or result in losses.

The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties the Company believes represent minimum credit risks. The Company cannot provide assurance that these trading counterparties will not become credit risks in the future. Hedging arrangements expose the Company to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements have limited and may continue to limit the benefit the Company could receive from increases in the prices for natural gas and oil. The Company cannot provide assurance that the hedging transactions it has entered into, or will enter into, will adequately protect it from fluctuations in natural gas and oil prices. The Company may choose not to engage in hedging transactions in the future. As a result, the Company may be adversely affected during periods of declining natural gas and oil prices.

Natural gas prices have fluctuated widely in early 2003. The Company will recognize net hedging losses of $17.7 million in the first quarter of 2003 based on natural gas price settlements. If natural gas prices remain at current levels, Spinnaker will incur significant hedging losses in the remainder of 2003.

The Company's success depends on its Chief Executive Officer and other key personnel, the loss of whom could disrupt business operations.

The Company depends to a large extent on the efforts and continued employment of the Company's President and Chief Executive Officer, Roger L. Jarvis, and other key personnel, including the Company's Vice President - Exploration who will retire in early 2004. If Mr. Jarvis or other key personnel resign or become unable to continue in their present role and if they are not adequately replaced, the Company's business operations could be adversely affected.

The Company is subject to complex laws and regulations, including environmental regulations, that can adversely affect the cost, manner or feasibility of doing business.

Exploration for and development, production and sale of natural gas and oil in the U.S. and especially in the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental laws and regulations. The Company may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations and taxation.

Under these laws and regulations, the Company could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. The Company does not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of its operations and subject the Company to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase costs. For example, Congress or the MMS could decide to limit exploratory drilling or natural gas production in additional areas of the Gulf of Mexico. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect the Company's financial condition and results of operations.

Competition in the industry is intense, and the Company is smaller and has a more limited operating history than most of its competitors in the Gulf of Mexico.

The Company competes with major and independent natural gas and oil companies for property acquisitions. It also competes for the equipment and labor required to operate and develop properties. Most of the competitors have substantially greater financial and other resources than the Company. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than the Company can, which would adversely affect its competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than the Company can. The Company's ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on its ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of the competitors have been operating in the Gulf of Mexico for a much longer time than the Company has and have demonstrated the ability to operate through industry cycles.

The Company cannot control the activities on properties it does not operate.

Other companies operate some of the properties in which the Company has an interest, including Front Runner. As a result, the Company has a limited ability to exercise influence over operations for these properties or their associated costs. The Company's dependence on the operator and other working interest owners for these projects and its limited ability to influence operations and associated costs could materially and adversely affect the realization of its targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of the Company's control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

The Company may have difficulty financing its planned growth.

The Company has experienced and expects to continue to experience substantial capital expenditure and working capital needs, particularly as a result of its drilling program. In the future, the Company expects it will require additional financing, in addition to cash generated from its operations, to fund its planned growth. The Company cannot be certain that additional financing will be available on acceptable terms or at all. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

Warburg owns a significant number of shares of Common Stock, giving it influence in corporate transactions and other matters, and the interests of Warburg could differ from those of other stockholders.

At December 31, 2002, Warburg owned approximately 20% of the outstanding shares of Common Stock. As a result, Warburg is in a position to significantly influence the outcome of matters requiring a stockholder vote, including the election of directors, the adoption of an amendment to the certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. Its influence over Spinnaker may delay or prevent a change of control of the Company and may adversely affect the voting and other rights of other stockholders.

Furthermore, conflicts of interest could arise in the future between the Company and Warburg concerning, among other things, potential competitive business activities or business opportunities. Warburg is not restricted from competitive natural gas and oil exploration and production activities or investments. Warburg currently has significant equity interests in other public and private natural gas and oil companies. The interests of Warburg could differ from those of other stockholders.

A portion of the Company's outstanding shares owned by Warburg or other significant stockholders may be sold into the market in the near future. This could cause the market price of the Common Stock to drop significantly, even if the Company's business is doing well.
The market price of the Common Stock could drop due to sales of a large number of shares of Common Stock in the market or the perception that such sales could occur. This could make it more difficult to raise funds through any future offering of Common Stock.

The certificate of incorporation and bylaws contain provisions that could discourage an acquisition or change of control of the Company.
The certificate of incorporation authorizes the board of directors to issue Preferred Stock without stockholder approval. If the board of directors elects to issue Preferred Stock, it could be more difficult for a third party to acquire control of the Company, even if that change of control might be beneficial to stockholders. In addition, provisions of the certificate of incorporation and bylaws, such as no stockholder action by written consent and limitations on stockholder proposals at meetings of stockholders, could also make it more difficult for a third party to acquire control of the Company.

Terrorist attacks on natural gas and oil production facilities, transportation systems and storage facilities could have a material adverse impact on the Company's business.
Natural gas and oil production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact if certain natural gas and oil infrastructure integral to the Company's operations were destroyed or damaged.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts. The Company's critical accounting policies are as follows:

FULL COST METHOD OF ACCOUNTING

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs, no exploration costs and higher DD&A rates than the application of the successful efforts method of accounting.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of December 31, 2002, the Company excluded from the amortization base estimated future expenditures of $29.4 million associated with common development costs for its deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

If the $29.4 million had been included in the amortization base as of December 31, 2002, and no additional reserves were assigned to the Front Runner project, the DD&A rate in 2002 would have been $2.21 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.12 per Mcfe. All future development costs associated with the deepwater discovery at Front Runner are included in the determination of estimated future net cash flows from proved natural gas and oil reserves used in the full cost ceiling calculation, as discussed below.

FULL COST CEILING

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of December 31, 2002, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

As of December 31, 2002, the Company's full cost ceiling, including estimated future net cash flows calculated using commodity prices of $4.91 per Mcf of natural gas and $30.50 per barrel of oil and condensate, exceeded capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, by approximately $139.9 million. Considering the volatility of natural gas and oil prices, it is probable that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas or oil prices decline, even if for only a short period of time, or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

CAPITALIZED EMPLOYEE AND OTHER GENERAL AND ADMINISTRATIVE COSTS

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $5.9 million, $5.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

UNPROVED PROPERTIES

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

NATURAL GAS AND OIL RESERVES

The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The Company must project production rates and timing of development expenditures. The Company analyzes available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. At December 31, 2002, approximately 82% of the Company's proved reserves were either undeveloped or non-producing. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

At December 31, 2002, approximately 70% of the Company's proved reserves were undeveloped and primarily related to Front Runner. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that the Company will make these expenditures. Although the Company estimates its reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated.

OTHER PROPERTY AND EQUIPMENT

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $1.5 million, $0.5 million and $1.2 million in 2002, 2001 and 2000, respectively.

COMMODITY PRICE RISK MANAGEMENT ACTIVITIES

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. See "Quantitative and Qualitative Disclosures About Market Risk."

STOCK-BASED COMPENSATION

SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock.

RELATED PARTIES

The Company purchases oilfield goods, equipment and services from Baker Hughes Incorporated ("Baker Hughes"), Cooper Cameron Corporation ("Cooper Cameron") and other oilfield services companies in the ordinary course of business. The Company incurred charges of approximately $16.1 million and $16.3 million in 2002 and 2001, respectively, from affiliates of Baker Hughes, of which Mr. Michael E. Wiley, a director of Spinnaker since March 2001, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.5 million in 2002, 2001 and 2000, respectively, from Cooper Cameron, of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President. Spinnaker believes that these transactions are at arm's-length and the charges it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry. Both of these companies are leaders in their respective segments of the oilfield services sector. The Company could be at a disadvantage if it were to discontinue using either company as vendors.

RESULTS OF OPERATIONS

The following table sets forth certain operating information with respect to the natural gas and oil operations of the Company:

Year Ended December 31,	2002	2001	2000
Production:			
Natural gas (MMcf)	45,180	51,234	28,845
Oil and condensate (MBbls)	1,040	310	225
Total (MMcfe)	51,419	53,094	30,194
Revenues (in thousands):			
Natural gas	$ 156,214	$ 212,238	$ 133,264
Oil and condensate	27,448	7,718	6,775
Net hedging income (loss)	4,664	(9,580)	(18,656)
Total	$ 188,326	$ 210,376	$ 121,383
Average sales price per unit:			
Natural gas revenues from production (per Mcf)	$ 3.46	$ 4.14	$ 4.62
Effects of hedging activities (per Mcf)	0.10	(0.18)	(0.59)
Average price (per Mcf)	$ 3.56	$ 3.96	$ 4.03
Oil and condensate revenues from production (per Bbl)	$ 26.39	$ 24.90	$ 30.14
Effects of hedging activities (per Bbl)	–	–	(7.16)
Average price (per Bbl)	$ 26.39	$ 24.90	$ 22.98
Total revenues from production (per Mcfe)	$ 3.57	$ 4.14	$ 4.64
Effects of hedging activities (per Mcfe)	0.09	(0.18)	(0.62)
Total average price (per Mcfe)	$ 3.66	$ 3.96	$ 4.02
Expenses (per Mcfe):			
Lease operating expenses	$ 0.35	$ 0.23	$ 0.30
Depreciation, depletion and amortization – natural gas and oil properties	$ 2.12	$ 1.60	$ 1.57
Income from operations (in thousands)	$ 49,090	$ 100,285	$ 57,264

YEAR ENDED DECEMBER 31, 2002 AS COMPARED TO THE YEAR ENDED DECEMBER 31, 2001

Revenues, including the effects of hedging activities, decreased $22.1 million in 2002 compared to 2001. Natural gas revenues decreased $56.0 million, oil and condensate revenues increased $19.7 million and revenues from natural gas hedging activities improved $14.2 million in 2002 compared to 2001.

Production decreased approximately 1.7 Bcfe in 2002 compared to 2001. Average daily production in 2002 was 141 MMcfe compared to 145 MMcfe in 2001. Natural gas revenues decreased $56.0 million due to lower volumes of 6.1 Bcf and a lower average price in 2002 compared to 2001. The production declines of certain producing wells, particularly in the High Island 202 area, resulted in lower natural gas production in 2002. Oil and condensate revenues increased $19.7 million primarily due to higher production volumes of 730 MBbls. The Company expects a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs.

Lease operating expenses increased $6.1 million in 2002 compared to 2001. Of the total increase in lease operating expenses, approximately $7.3 million was attributable to wells on ten new blocks that commenced production in 2002, offset in part by a decrease of $0.9 million in operating expenses associated with existing wells and a decrease of $0.3 million in workovers. The overall increase in the lease operating expense rate per Mcfe in 2002 compared to 2001 was primarily due to the production declines of certain wells in the High Island 202 area where the lease operating rate in 2001 was significantly lower compared to other producing areas operated by the Company. Additionally, the Company is experiencing higher lease operating rates associated with new wells compared to historical average lease operating rates due to well locations, transportation and gathering agreements and processing requirements.

DD&A increased $23.9 million in 2002 compared to 2001. Of the total increase in DD&A, $26.6 million related to an increase in the DD&A rate, offset in part by $2.7 million related to lower production volumes of 1.7 Bcfe in 2002 compared to 2001. The increase in the DD&A rate in 2002 was primarily due to costs of $72.6 million associated with 12 unsuccessful wells and higher finding costs associated with new discoveries in 2002.

General and administrative expenses increased $1.5 million in 2002 compared to 2001. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth and increased professional services fees.

Interest income decreased $2.6 million in 2002 compared to 2001 primarily due to lower average cash and short-term investment balances and significantly lower interest rates in 2002. Interest expense increased $0.3 million in 2002 compared to 2001 primarily due to interest on borrowings of $37.0 million in the first quarter of 2002 and higher commitment fees. On April 3, 2002, the Company repaid all of its outstanding borrowings of $37.0 million under the Credit Facility.

Income tax expense decreased $19.5 million in 2002 compared to 2001 due to lower earnings in 2002. Income taxes were accrued at a 36% effective tax rate in 2002 and 2001.

The Company recognized net income of $31.6 million, or $1.00 per basic share and $0.97 per diluted share, in 2002 compared to net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001.

YEAR ENDED DECEMBER 31, 2001 AS COMPARED TO THE YEAR ENDED DECEMBER 31, 2000

Revenues increased $89.0 million in 2001 compared to 2000. Excluding the effects of hedging activities, natural gas revenues increased $79.0 million and oil and condensate revenues increased $0.9 million. Losses resulting from hedging activities decreased by $9.1 million in 2001 compared to 2000, thereby improving revenues.

Production increased approximately 22.9 Bcfe in 2001 compared to 2000. Average daily production in 2001 was 145 MMcfe compared to 82 MMcfe in 2000. Natural gas production volumes increased 22.4 Bcf, contributing $123.9 million of the increase in natural gas revenues, excluding the effects of hedging activities, offset in part by $44.9 million related to lower average natural gas prices in 2001 compared to 2000. Oil and condensate production volumes increased 85 MBbls, contributing $2.8 million of the increase in oil and condensate revenues, offset in part by $1.9 million related to decreases in average oil and condensate prices. The rapid production declines of certain producing wells, combined with pipeline-mandated curtailments of certain facilities, shut-ins related to facility upgrades and less than anticipated results from workovers resulted in lower production in the fourth quarter of 2001 compared to the prior quarter.

Lease operating expenses increased $3.1 million in 2001 compared to 2000. Of the total increase in lease operating expenses, $1.0 million was primarily related to workover activities in 2001 and $0.4 million was attributable to wells on new blocks that commenced production subsequent to December 31, 2000. The lease operating expense rate decreased 23% to $0.23 per Mcfe in 2001 compared to 2000 primarily due to increased production coupled with continued efficiencies gained in core operating areas, including the High Island 202 area.

DD&A increased $37.7 million in 2001 compared to 2000. The change in DD&A was attributable to an increase in production of 22.9 Bcfe and a slightly higher DD&A rate, which impacted DD&A by $36.0 million and $1.7 million, respectively.

General and administrative expenses increased $2.1 million in 2001 compared to 2000. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million related to these receivables.

Interest income increased $0.7 million in 2001 compared to 2000 primarily due to investment income associated with proceeds from the Company's public offering of Common Stock completed on August 16, 2000. Interest expense decreased $0.4 million in 2001 compared to 2000. The Company had no outstanding borrowings in 2001 compared to 2000.

Income tax expense increased $16.4 million in 2001 compared to 2000 and primarily relates to deferred income taxes accrued at a 36% effective tax rate in 2001 and a 35% effective tax rate in 2000.

The Company recognized net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001 compared to net income of $38.6 million, or $1.70 per basic share and $1.61 per diluted share, in 2000.

LIQUIDITY AND CAPITAL RESOURCES

The Company has experienced and expects to continue to experience substantial capital requirements, primarily due to its active exploration and development programs in the Gulf of Mexico. Spinnaker has capital expenditure plans for 2003 totaling approximately $250.0 million. Spinnaker has participated in a significant deepwater oil discovery, Front Runner, with a 25% non-operator working interest. Spinnaker incurred capital expenditures associated with Front Runner of $40.8 million in 2002 and $70.2 million from inception through December 31, 2002. The Company expects to incur approximately $86.0 million in future development costs related to Front Runner, including approximately $46.0 million in 2003, $21.0 million in 2004 and $19.0 million thereafter.

Natural gas and oil prices have a significant impact on the Company's cash flows available for capital expenditures and its ability to borrow and raise additional capital. The amount the Company can borrow under its Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. Additionally, the rapid production declines of certain producing wells resulted in lower production in 2002. The Company expects a decline in production during the first quarter of 2003 from the 16.3 Bcfe reported in the fourth quarter of 2002 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Credit Facility, thus reducing the amount of financial resources available to meet the Company's capital requirements. The Company believes that working capital, cash flows from operations and proceeds from available borrowings under its Credit Facility will be sufficient to meet its capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and exploration and development programs. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million. On April 3, 2002, the Company used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million. The remaining net proceeds were invested in short-term high quality investments and are being used to fund a portion of the costs to develop the Company's deepwater oil discovery at Front Runner, to fund a portion of exploration and other development activities and for general corporate purposes, including possible acquisitions of properties or seismic data.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

Cash and cash equivalents increased $18.5 million to $32.5 million at December 31, 2002. The components of the increase in cash and cash equivalents include $154.0 million provided by operating activities, $363.8 million used in investing activities and $228.3 million provided by financing activities.

OPERATING ACTIVITIES

Net cash provided by operating activities in 2002 decreased 26% to $154.0 million primarily due to lower commodity prices and production. Cash flow from operations is dependent upon the Company's ability to increase production through its exploration and development programs and the prices of natural gas and oil. The Company has made significant investments to expand its operations in the Gulf of Mexico. These investments increased the Company's average daily production in the fourth quarter of 2002 as compared to prior quarters; however, the Company expects a decline in production during the first quarter of 2003 from the 16.3 Bcfe reported in the fourth quarter of 2002.

The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. See "Quantitative and Qualitative Disclosures About Market Risk."

The Company's cash flow from operations also depends on its ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net increase of $13.4 million in accounts receivable was primarily related to an increase in the natural gas and oil revenue accrual due to higher production and commodity prices in December 2002 compared to December 2001. The net decrease of $15.1 million in accounts payable and accrued liabilities was primarily due to the reversal of current deferred taxes of $7.2 million related to the fair value of open derivative contracts at December 31, 2001. In connection with the fair value of open derivative contracts at December 31, 2002, the Company recorded a net deferred tax asset of $7.2 million in other current assets.

INVESTING ACTIVITIES

Net cash used in investing activities in 2002 increased 37% to $363.8 million compared to 2001. Net oil and gas property capital expenditures were $356.6 million and other property and equipment capital expenditures were $7.2 million.

As part of its strategy, the Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower waters. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. The Company has experienced and will continue to experience significantly higher drilling costs for its deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. The Company drilled 26 wells in 2002, 14 of which were successful. In 2001, the Company drilled 35 wells, 19 of which were successful. Since inception and through December 31, 2002, the Company has drilled 120 wells, 70 of which were successful, representing a success rate of 58%. Dry hole costs, including associated leasehold costs, were $72.6 million in 2002.

Purchases of other property and equipment increased to $7.2 million in 2002 primarily due to expenditures for seismic hardware and software of $4.1 million, leasehold improvements of $1.4 million and other hardware and software upgrades and other equipment of $1.7 million.

The Company has capital expenditure plans for 2003 totaling approximately $250.0 million, primarily for costs related to exploration and development programs. The Company does not anticipate any significant abandonment or dismantlement costs in 2003. Actual levels of capital expenditures may vary due to many factors, including drilling results, natural gas and oil prices, the availability of capital, industry conditions, acquisitions, decisions of operators and other prospect owners and the prices of drilling rig dayrates and other oilfield goods and services. In 2002, the Company incurred acquisition, exploration and development costs of $39.8 million, $163.3 million and $139.4 million, respectively. The costs associated with unproved properties and properties under development not included in the amortization base were $141.3 million and $102.9 million as of December 31, 2002 and 2001, respectively, and included the following (in thousands):

As of December 31,	2002	2001
Leasehold, delay rentals and seismic data	$ 122,409	$ 92,150
Wells in-progress	17,639	10,112
Other	1,278	619
Total	$ 141,326	$ 102,881

FINANCING ACTIVITIES

Net cash provided by financing activities of $228.3 million in 2002 included proceeds from the public offering of Common Stock and $37.0 million in proceeds from and subsequent payments on borrowings. The Company received net proceeds of $227.9 million from the Common Stock offering on April 3, 2002, and used a portion of the proceeds from the offering to repay outstanding borrowings of $37.0 million.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million Credit Facility with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base at their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks' view of the Company's reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;
- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;
- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;
- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;
- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;
- must maintain a tangible net worth so that it is not less than the sum of 80% of the tangible net worth as of September 30, 2001, plus 50% of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75% of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and
- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100% for the period one to three months from and after the hedging agreement transaction date, 66⅔% for the period four to 18 months from and after the hedging agreement transaction date and 33⅓% for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2002, the Company was in compliance with the covenants and restrictive provisions and had no outstanding borrowings under the Credit Facility. The Company expects to borrow under the Credit Facility in 2003 and be in compliance with the covenants and restrictive provisions for the next twelve months.

CONTRACTUAL OBLIGATIONS

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of December 31, 2002. The Company has incurred obligations in the ordinary course of business under purchase and service agreements that are not included in the table below, including obligations of approximately $35.4 million and $6.7 million in 2003 and 2004, respectively, for construction of the Front Runner spar production facility. Operating lease obligations as of December 31, 2002 are as follows (in thousands):

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases	$ 6,032	$ 1,708	$ 3,800	$ 524	$ –
Other contractual obligations	–	–	–	–	–
Total	$ 6,032	$ 1,708	$ 3,800	$ 524	$ –

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

INTEREST RATE RISK

The Company is exposed to changes in interest rates. Changes in interest rates affect the interest earned on cash and cash equivalents and the interest rate paid on borrowings under the Credit Facility. The Company does not currently use interest rate derivative instruments to manage exposure to interest rate changes, but may do so in the future.

COMMODITY PRICE RISK

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. Spinnaker does not enter into such hedging arrangements for trading purposes. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements are fixed price swap contracts and cashless collar arrangements and are placed with major trading counterparties the Company believes represent minimum credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. Under its current hedging practice, the Company generally does not hedge more than 66⅔% of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting.

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of December 31, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003	60,000	$ 3.71	$ (5,979)
Second Quarter 2003	53,297	3.55	(4,411)
Third Quarter 2003	50,000	3.55	(4,068)
Fourth Quarter 2003	50,000	3.63	(4,340)
Year 2003	53,288	$ 3.61	$ (18,798)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of December 31, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003	15,000	$ 3.25	$ 5.21	$ (228)
Second Quarter 2003	15,000	3.25	5.21	(262)
Third Quarter 2003	15,000	3.25	5.21	(287)
Fourth Quarter 2003	15,000	3.25	5.21	(342)
Year 2003	15,000	$ 3.25	$ 5.21	$ (1,119)

The Company reported a net liability of $19.9 million and a net asset of $22.3 million related to its derivative contracts at December 31, 2002 and 2001, respectively. Amounts related to hedging activities as of December 31, 2002 and 2001 were as follows (in thousands):

As of December 31,	2002	2001
Current assets:		
Hedging asset	$ –	$ 20,593
Deferred tax asset related to hedging activities	7,170	–
Non-current assets:		
Hedging asset	$ –	$ 1,726
Current liabilities:		
Hedging liability	$ 19,917	$ –
Deferred tax liability related to hedging activities	–	7,208
Non-current liabilities:		
Deferred tax liability related to hedging activities	$ –	$ 604
Accumulated other comprehensive income (loss):		
Accumulated other comprehensive income (loss)	$ (19,917)	$ 22,319
Income taxes	7,170	(7,812)
Accumulated other comprehensive income (loss)	$ (12,747)	$ 14,507

The Company recognized a net hedging gain of $4.7 million and net hedging losses of $9.6 million and $18.7 million in revenues in 2002, 2001 and 2000, respectively. There was no ineffective component of the derivatives recognized in earnings in 2002 and 2001. Based on future natural gas prices as of December 31, 2002, the Company would reclassify a net loss of $12.7 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

Subsequent to December 31, 2002, Spinnaker has not entered into additional hedging arrangements. Natural gas prices have fluctuated widely in early 2003. The Company will recognize net hedging losses of $17.7 million in the first quarter of 2003 based on natural gas price settlements. If natural gas prices remain at current levels, Spinnaker will incur significant hedging losses in the remainder of 2003.

To calculate the potential effect of the derivative contracts on future revenues, the Company applied natural gas forward prices as of December 31, 2002 to the quantity of the Company's natural gas production covered by those derivative contracts as of that date. The following table shows the estimated potential effects of the derivative financial instruments on future revenues (in thousands):

Derivative Instrument	Estimated Decrease in Revenues at Current Prices	Estimated Decrease in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Fixed price swap transactions	$ (18,798)	$ (10,926)	$ (26,912)
Collar arrangements	$ (1,119)	$ (289)	$ (2,216)

Independent Auditors' Report

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF
SPINNAKER EXPLORATION COMPANY:

We have audited the accompanying consolidated balance sheets of Spinnaker Exploration Company and subsidiaries, as of December 31, 2002 and 2001, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spinnaker Exploration Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for its derivative instruments.

KPMG LLP

Houston, Texas
February 7, 2003

SPINNAKER EXPLORATION COMPANY

Consolidated Balance Sheets

(In thousands, except share and per share data)

As of December 31,	2002	2001
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 32,543	$ 14,061
Accounts receivable, net of allowance for doubtful accounts of $3,232 and $3,059 at December 31, 2002 and 2001, respectively	37,572	24,129
Hedging assets	–	20,593
Other	11,438	3,664
Total current assets	81,553	62,447
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	879,840	575,806
Unproved properties and properties under development, not being amortized	141,326	102,881
Other	14,461	7,245
	1,035,627	685,932
Less - Accumulated depreciation, depletion and amortization	(274,773)	(163,359)
Total property and equipment	760,854	522,573
OTHER ASSETS	308	2,296
Total assets	$ 842,715	$ 587,316
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 29,453	$ 32,383
Accrued liabilities and other	38,542	50,718
Hedging liabilities	19,917	–
Total current liabilities	87,912	83,101
DEFERRED INCOME TAXES	61,826	45,723
COMMITMENTS AND CONTINGENCIES (Note 11)		
EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at December 31, 2002 and 2001, respectively	–	–
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,184,463 shares issued and 33,171,759 shares outstanding at December 31, 2002 and 27,308,912 shares issued and 27,293,264 shares outstanding at December 31, 2001	332	273
Additional paid-in capital	596,087	365,993
Retained earnings	109,337	77,758
Less: Treasury stock, at cost, 12,704 and 15,648 shares at December 31, 2002 and 2001, respectively	(32)	(39)
Accumulated other comprehensive income (loss)	(12,747)	14,507
Total equity	692,977	458,492
Total liabilities and equity	$ 842,715	$ 587,316

The accompanying notes are an integral part of these consolidated financial statements.

SPINNAKER EXPLORATION COMPANY

Consolidated Statements of Operations

(In thousands, except per share data)

Year Ended December 31,	2002	2001	2000
REVENUES	$ 188,326	$ 210,376	$ 121,383
EXPENSES:			
Lease operating expenses	18,212	12,132	9,009
Depreciation, depletion and amortization - natural gas and oil properties	108,998	85,059	47,451
Depreciation and amortization - other	914	398	309
General and administrative	10,984	9,443	7,350
Charges related to Enron bankruptcy	128	3,059	–
Total expenses	139,236	110,091	64,119
INCOME FROM OPERATIONS	49,090	100,285	57,264
OTHER INCOME (EXPENSE):			
Interest income	1,014	3,574	2,908
Interest expense, net	(762)	(381)	(748)
Total other income (expense)	252	3,193	2,160
INCOME BEFORE INCOME TAXES	49,342	103,478	59,424
Income tax expense	17,763	37,252	20,858
NET INCOME	$ 31,579	$ 66,226	$ 38,566
NET INCOME PER COMMON SHARE:			
Basic	$ 1.00	$ 2.45	$ 1.70
Diluted	$ 0.97	$ 2.34	$ 1.61
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	31,695	27,079	22,679
Diluted	32,653	28,360	24,011

The accompanying notes are an integral part of these consolidated financial statements.

SPINNAKER EXPLORATION COMPANY

Consolidated Statements of Equity

(In thousands, except share data)

	Shares Issued: Preferred	Shares Issued: Common	Par Value: Preferred	Par Value: Common	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Equity	Comprehensive Income (Loss)
Balance,										
December 31, 1999	–	20,426,192	$ –	$ 204	$ 203,987	$ (27,034)	$ (55)	$ –	$ 177,102	
Net income	–	–	–	–	–	38,566	–	–	38,566	$ 38,566
Comprehensive income										$ 38,566
Common stock issuance, net of issuance costs	–	5,600,000	–	56	138,342	–	–	–	138,398	
Exercise of stock options	–	462,478	–	5	3,195	–	11	–	3,211	
Employer contributions to 401(k) Plan	–	5,923	–	–	148	–	–	–	148	
Stock compensation costs	–	–	–	–	158	–	–	–	158	
Tax benefit associated with exercise of non-qualified stock options	–	–	–	–	3,676	–	–	–	3,676	
Balance,										
December 31, 2000	–	26,494,593	$ –	$ 265	$ 349,506	$ 11,532	$ (44)	$ –	$ 361,259	
Net income	–	–	–	–	–	66,226	–	–	66,226	$ 66,226
Other comprehensive income, net of tax:										
Cumulative effect of accounting change for derivative financial instruments	–	–	–	–	–	–	–	(27,126)	(27,126)	(27,126)
Net change in fair value of derivative financial instruments	–	–	–	–	–	–	–	35,502	35,502	35,502
Financial derivative settlements reclassed to income	–	–	–	–	–	–	–	6,131	6,131	6,131
Comprehensive income										$ 80,733
Exercise of stock options	–	808,863	–	8	7,142	–	5	–	7,155	
Employer contributions to 401(k) Plan	–	5,456	–	–	216	–	–	–	216	
Stock compensation costs	–	–	–	–	114	–	–	–	114	
Tax benefit associated with exercise of non-qualified stock options	–	–	–	–	9,015	–	–	–	9,015	
Balance,										
December 31, 2001	–	27,308,912	$ –	$ 273	$ 365,993	$ 77,758	$ (39)	$ 14,507	$458,492	
Net income	–	–	–	–	–	31,579	–	–	31,579	$ 31,579
Other comprehensive income, net of tax:										
Net change in fair value of derivative financial instruments	–	–	–	–	–	–	–	(24,269)	(24,269)	(24,269)
Financial derivative settlements reclassed to income	–	–	–	–	–	–	–	(2,985)	(2,985)	(2,985)
Comprehensive income										$ 4,325
Common stock issuance, net of issuance costs	–	5,750,000	–	58	227,326	–	–	–	227,384	
Exercise of stock options	–	116,489	–	1	948	–	7	–	956	
Employer contributions to 401(k) Plan	–	9,062	–	–	287	–	–	–	287	
Stock compensation costs	–	–	–	–	177	–	–	–	177	
Tax benefit associated with exercise of non-qualified stock options	–	–	–	–	1,356	–	–	–	1,356	
Balance,										
December 31, 2002	–	33,184,463	$ –	$ 332	$ 596,087	$ 109,337	$ (32)	$ (12,747)	$692,977	

The accompanying notes are an integral part of these consolidated financial statements.

SPINNAKER EXPLORATION COMPANY

Consolidated Statements of Cash Flows

(In thousands)

Year Ended December 31,	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 31,579	$ 66,226	$ 38,566
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	109,912	85,457	47,760
Deferred income tax expense	18,063	36,977	20,833
Other	881	549	306
Change in operating assets and liabilities:			
Accounts receivable	(13,443)	21,465	(34,799)
Accounts payable and accrued liabilities	7,726	(3,216)	14,861
Other assets	(759)	1,979	(5,523)
Net cash provided by operating activities	153,959	209,437	82,004
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties	(356,601)	(287,225)	(161,811)
Proceeds from sale of natural gas and oil assets	–	–	5,971
Purchases of other property and equipment	(7,216)	(1,603)	(1,928)
Purchases of short-term investments	–	(29,627)	(22,387)
Sales of short-term investments	–	52,014	–
Net cash used in investing activities	(363,817)	(266,441)	(180,155)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	37,000	–	17,000
Payments on borrowings	(37,000)	–	(17,000)
Proceeds from issuance of common stock	227,873	–	138,936
Common stock issuance costs	(489)	–	(538)
Proceeds from exercise of stock options	956	7,155	3,211
Net cash provided by financing activities	228,340	7,155	141,609
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	18,482	(49,849)	43,458
CASH AND CASH EQUIVALENTS, beginning of year	14,061	63,910	20,452
CASH AND CASH EQUIVALENTS, end of year	$ 32,543	$ 14,061	$ 63,910
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest, net of amounts capitalized	$ 468	$ 190	$ 380
Cash paid (received) for income taxes, net	$ (300)	$ 275	$ 25

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

1. ORGANIZATION:

Spinnaker Exploration Company ("Spinnaker" or the "Company") was formed in 1996 and engages in the exploration, development and production of natural gas and oil properties in the U.S. Gulf of Mexico.

On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of common stock, par value $0.01 per share ("Common Stock"), and commenced trading the following day. After payment of underwriting discounts and commissions, the Company received net proceeds of $108.7 million on October 4, 1999. With a portion of the proceeds, the Company retired all outstanding debt of $72.0 million. In connection with the initial public offering, the Company converted all outstanding Series A Convertible Preferred Stock, par value $0.01 per share ("Preferred Stock"), into shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into shares of Common Stock.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below:

GENERAL

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States and pursuant to the rules and regulations of the Securities and Exchange Commission (the "Commission").

PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements include the activities and accounts of the Company and its subsidiaries, all of which are wholly owned. All significant intercompany transactions and balances are eliminated in consolidation.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available.

CASH EQUIVALENTS

The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

OTHER CURRENT ASSETS

Other current assets include unamortized debt financing costs of $0.3 million and $0.3 million at December 31, 2002 and 2001, respectively. Other non-current assets include unamortized debt financing costs of $0.3 million and $0.6 million at December 31, 2002 and 2001, respectively. These costs are amortized to interest expense over the three-year term of the related credit facility. Amortization of these and other debt financing costs included in interest expense was $0.3 million, $0.2 million and $0.4 million for the years ended December 31, 2002, 2001 and 2000, respectively.

FULL COST METHOD OF ACCOUNTING

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. Substantially all the Company's exploration activities are conducted jointly with others and, accordingly, the natural gas and oil property balances reflect only its proportionate interest in such activities.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values.

Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

As of December 31, 2002, the Company excluded from the amortization base estimated future expenditures of $29.4 million associated with common development costs for its deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

FULL COST CEILING

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of December 31, 2002, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

CAPITALIZED EMPLOYEE AND OTHER GENERAL AND ADMINISTRATIVE COSTS

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $5.9 million, $5.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

UNPROVED PROPERTIES

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Of the $141.3 million of net unproved property costs at December 31, 2002 excluded from the amortizable base, net costs of $38.4 million, $19.7 million and $42.5 million were incurred in 2002, 2001 and 2000, respectively, and $40.7 million was incurred prior to 2000. The majority of the costs will be evaluated over the next five years.

OTHER PROPERTY AND EQUIPMENT

Other property and equipment consists of computer hardware and software, office furniture and leasehold improvements. The Company is depreciating these assets using the straight-line method based upon estimated useful lives ranging from three to five years.

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $1.5 million, $0.5 million and $1.2 million in 2002, 2001 and 2000, respectively.

REVENUE RECOGNITION POLICY

The Company records as revenue only that portion of production sold and delivered and allocable to its ownership interest in the related property. Imbalances arise when a purchaser takes delivery of more or less volume from a property than the Company's actual interest in the production from that property. Such imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Under-imbalances included in accounts receivable were $0.6 million and $0.7 million at December 31, 2002 and 2001, respectively. Over-imbalances included in accrued liabilities were $2.5 million and $0.7 million at December 31, 2002 and 2001, respectively.

INCOME TAXES

Under Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes," deferred income taxes are recognized at each year-end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

STOCK-BASED COMPENSATION

SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock. In accordance with APB Opinion No. 25, compensation expense related to stock-based compensation was \$0.2 million, \$0.1 million and \$0.2 million in 2002, 2001 and 2000, respectively. Had compensation cost for the Company's stock option compensation plans been determined based on the fair value at the grant dates for awards under these plans consistent with the method of SFAS No. 123, the Company's pro forma net income and pro forma net income per common share would have been as follows (in thousands, except per share amounts):

Year Ended December 31,	2002	2001	2000
Net income, as reported	$ 31,579	$ 66,226	$ 38,566
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	114	73	103
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8,902)	(8,920)	(3,126)
Pro forma net income	$ 22,791	$ 57,379	$ 35,543
Net income per common share:			
Basic, as reported	$ 1.00	$ 2.45	$ 1.70
Basic, pro forma	$ 0.72	$ 2.12	$ 1.57
Diluted, as reported	$ 0.97	$ 2.34	$ 1.61
Diluted, pro forma	$ 0.70	$ 2.02	$ 1.48

For purposes of the SFAS No. 123 disclosure, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with assumptions for grants in 2002, 2001 and 2000 as follows:

Year Ended December 31,	2002	2001	2000
Risk-free interest rate	3.98%-5.28%	4.85%-5.57%	5.14%-6.82%
Volatility factor	62.2%	43.0%	42.5%
Dividend yield	0%	0%	0%
Expected life of the options (years)	4	4	4

FINANCIAL INSTRUMENTS AND PRICE RISK MANAGEMENT ACTIVITIES

At December 31, 2002, the Company's financial instruments consisted of cash and cash equivalents, receivables, payables and derivative instruments. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value because of the short-term nature of these items. The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties.

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged items in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. Upon adoption of SFAS No. 133 on January 1, 2001, the Company designated its open derivative contracts as cash flow hedges and recorded (i) a net current liability of $41.7 million, representing the fair market value of all derivatives on that date and (ii) a reduction of equity through accumulated other comprehensive income (loss) of $27.1 million, representing the fair market value of the derivatives as of January 1, 2001, net of deferred income taxes of $14.6 million.

CONCENTRATION OF CREDIT RISK

Financial instruments that potentially subject the Company to concentration of credit risk consist principally of cash equivalents and trade accounts receivable. Derivative contracts also subject the Company to concentration of credit risk. Management believes that the credit risk posed by this concentration is mitigated by its hedging policy. The hedging policy requires that (i) at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and (ii) at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million related to these receivables.

NEW ACCOUNTING PRONOUNCEMENTS

SFAS No. 143, "Accounting for Asset Retirement Obligations," requires entities to record a liability for asset retirement obligations at fair value in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 30, 2002 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation, depletion and amortization. The Company will adopt SFAS No. 143 effective January 1, 2003. The Company expects the adoption of this statement to result in the recognition of a liability for asset retirement obligations of approximately $22-$26 million, approximately $2-$4 million of which will be included in current liabilities and approximately $20-$22 million of which will be included in non-current liabilities, an increase in property and equipment of approximately $18-$22 million in the Company's balance sheets, and a cumulative accounting adjustment of approximately $2-$4 million recorded as expense, net of taxes of $1-$2 million, as the effect of the change in accounting principle.

SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends APB Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002.

3. ACCOUNTS RECEIVABLE, OTHER CURRENT ASSETS AND ACCRUED LIABILITIES AND OTHER:

Supplemental disclosures related to accounts receivable, other current assets and accrued liabilities and other are as follows (in thousands):

As of December 31,	2002	2001
Accounts receivable:		
Natural gas and oil sales	$ 24,434	$ 10,679
Hedging receivable	2,093	2,093
Joint interest billings	10,430	8,735
Insurance claims receivable	3,127	4,593
Other receivables	720	1,088
Allowance for doubtful accounts	(3,232)	(3,059)
Total accounts receivable	$ 37,572	$ 24,129
Other current assets:		
Deferred tax assets associated with hedging activities	$ 7,170	$ 115
Drilling advances	2,060	710
Prepaid insurance	648	1,664
Prepaid debt financing costs	301	328
Other	1,259	847
Total other current assets	$ 11,438	$ 3,664

As of December 31,	2002	2001
Accrued liabilities and other:		
Accrued liabilities	$ 38,542	$ 43,510
Deferred income taxes associated with hedging activities	–	7,208
Total accrued liabilities and other	$ 38,542	$ 50,718

4. DEBT:

In October 1999, the Company, Bank of Montreal and Credit Suisse First Boston entered into the $25.0 million Amended and Restated 364-Day Credit Agreement ("First Amended Credit Agreement"). The First Amended Credit Agreement was amended on July 20, 2000. The Second Amended and Restated Credit Agreement provided a $75.0 million credit facility ("Second Amended Credit Agreement") with an initial borrowing base of $40.0 million and an original term of 364 days. The borrowing base as of December 31, 2000 was $30.0 million. The Second Amended Credit Agreement was renewed for an additional 364-day term on July 18, 2001 before being terminated on December 28, 2001.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million credit facility ("Credit Facility") with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on or about April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base at their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks' view of the Company's reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;
- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;
- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;
- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;

- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;
- must maintain a tangible net worth so that it is not less than the sum of 80% of the tangible net worth as of September 30, 2001, plus 50% of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75% of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and
- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100% for the period one to three months from and after the hedging agreement transaction date, 66⅔% for the period four to 18 months from and after the hedging agreement transaction date and 33⅓% for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poor's or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and at no time will exposure to any single counterparty exceed 25% of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2002, the Company was in compliance with the covenants and restrictive provisions and had no outstanding borrowings under the Credit Facility.

5. EQUITY:

Prior to Spinnaker's initial public offering in September 1999, the Company sold Preferred Stock to various investors. On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of Common Stock and commenced trading the following day. In connection with the initial public offering, the Company converted all outstanding Preferred Stock into 6,061,840 shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into 1,200,248 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock at $26.25 per share. After payment of underwriting discounts and commissions, the Company received net proceeds of $138.9 million. On December 20, 2000, PGS sold its 5,388,743 shares of Common Stock at $29.25 per share. Spinnaker received no proceeds from this sale. On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

6. STOCK PLANS:

At December 31, 2002, officers, directors and employees had been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000 and 2001. The exercise price of each option equals the market price of Spinnaker's Common Stock on the date of grant. Stock option grants generally vest ratably over four years, with 20% vesting on the date of grant and 20% vesting in each of the succeeding four years, and expire after ten years. In the event of certain significant changes in control of the Company, all options then outstanding generally will become immediately exercisable in full.

In January 1998, the stockholders approved the 1998 Stock Option Plan ("1998 Plan"). The 1998 Plan was amended and restated in September 1999 and authorized the issuance of 2,673,242 shares of Common Stock. In September 1999, the stockholders approved the Adjunct Stock Option Plan ("Adjunct Plan"). The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920 shares. In September 1999, the stockholders approved the 1999 Stock Incentive Plan ("1999 Plan"). The number of shares of Common Stock that may be issued under the 1999 Plan may not exceed 1,300,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 1999 Plan to any one individual during any calendar year may not exceed 300,000 shares. In connection with the 1999 Plan, the stockholders approved the Adjunct Stock Option Plan ("Adjunct Plan"). The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920 shares. In November 2000, the board of directors adopted the 2000 Stock Option Plan ("2000 Plan"). Stockholder approval was not required for the 2000 Plan. The number of shares of Common Stock that may be issued under the 2000 Plan may not exceed 500,000 shares. In May 2001, the stockholders approved the 2001 Stock Incentive Plan ("2001 Plan"). The number of shares of Common Stock that may be issued under the 2001 Plan may not exceed 1,500,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 2001 Plan to any one individual during any calendar year may not exceed 300,000 shares.

Presented below is a summary of stock option activity.

	2002		2001		2000	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
Outstanding, beginning of year	4,062,556	$ 22.08	3,718,886	$ 13.80	3,382,974	$ 10.56
Granted	450,000	35.82	1,242,800	37.90	802,470	23.45
Exercised	(119,433)	8.01	(810,991)	8.82	(466,558)	6.88
Forfeited	(6,590)	27.64	(88,139)	17.57	–	–
Outstanding, end of year	4,386,533	$ 23.87	4,062,556	$ 22.08	3,718,886	$ 13.80
Exercisable, end of year	2,845,250	$ 19.30	2,273,548	$ 16.16	2,364,270	$ 11.38
Available for grant, end of year	204,535		648,545		303,206	
Weighted average fair value of options granted during the year	$ 26.83		$ 23.76		$ 15.17	

The Company transferred treasury shares to certain employees in connection with their exercises of 2,944, 2,128 and 4,080 options in 2002, 2001 and 2000, respectively. Options to purchase 1,240 shares of Common Stock were forfeited during 2002 and 1999 and are not currently available for future grants due to exercise price restrictions under the 1998 Plan.

At December 31, 2002, the following options were outstanding and exercisable and had the indicated weighted average remaining contractual lives:

	Outstanding		Exercisable		
Range of Exercise Prices Per Share	Number of Options	Weighted Average Exercise Price Per Share	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life (Years)
$2.50 - $5.00	541,004	$ 4.94	541,004	$ 4.94	4.2
$14.50 - $16.13	1,749,699	15.36	1,462,164	15.36	5.7
$21.58 - $26.88	322,700	26.05	172,200	26.41	8.2
$31.33 - $36.81	173,220	32.74	60,932	32.23	8.8
$37.35 - $38.63	1,407,210	37.84	529,530	37.86	8.4
$39.35 - $42.06	192,700	40.50	79,420	40.80	8.6
	4,386,533		2,845,250		

7. EARNINGS PER SHARE:

Basic and diluted net income per common share is computed based on the following information (in thousands, except per share amounts):

Year Ended December 31,	2002	2001	2000
Numerator:			
Net income available to common stockholders	$ 31,579	$ 66,226	$ 38,566
Denominator:			
Basic weighted average number of shares	31,695	27,079	22,679
Dilutive securities:			
Stock options	958	1,281	1,332
Diluted adjusted weighted average number of shares and assumed conversions	32,653	28,360	24,011
Net income per common share:			
Basic	$ 1.00	$ 2.45	$ 1.70
Diluted	$ 0.97	$ 2.34	$ 1.61

For the years ended December 31, 2002, 2001 and 2000, 1,680,640, 113,200 and 399,920 stock options that could potentially dilute earnings per share are excluded from the calculations as they were anti-dilutive.

8. MAJOR CUSTOMERS:

The Company had natural gas and oil sales to four customers accounting for approximately 52%, 13%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2002. The Company had natural gas and oil sales to four customers accounting for approximately 32%, 23%, 21% and 17%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2001. The Company had natural gas and oil sales to three customers accounting for approximately 61%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2000. One of the customers in 2001 and 2000 was Enron North America Corp. Spinnaker no longer sells its natural gas and oil production to this customer.

9. RELATED-PARTY TRANSACTIONS:

The Company incurred charges of approximately $16.1 million and $16.3 million in 2002 and 2001, respectively, from affiliates of Baker Hughes Incorporated, an oilfield services company of which Mr. Michael E. Wiley, a director of Spinnaker since March 2001, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.5 million in 2002, 2001 and 2000, respectively, from Cooper Cameron Corporation, an oilfield services company of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President.

10. INCOME TAXES:

The significant items giving rise to the deferred income tax assets and liabilities are as follows (in thousands):

As of December 31,	2002	2001
Deferred income tax liabilities:		
Basis differences in natural gas and oil properties	$ 156,588	$ 104,141
Hedging activities	–	7,812
Total deferred income tax liabilities	156,588	111,953
Deferred income tax assets:		
Net operating losses	$ 92,650	$ 58,400
Hedging activities	7,170	–
Other	2,112	622
Total deferred income tax assets	101,932	59,022
Net deferred income tax liabilities	$ 54,656	$ 52,931

Tax benefits of $1.4 million and $9.0 million associated with the exercise of non-qualified stock options during the years ended December 31, 2002 and 2001 are reflected as a component of equity. The net deferred income tax liabilities include a deferred tax asset of $7.2 million and a deferred tax liability of $7.8 million related to the tax effect of the fair market value of derivatives at December 31, 2002 and 2001, respectively, as required by SFAS No. 133, as amended.

As of December 31, 2002, the Company had approximately $257.4 million of net operating loss carryforwards ("NOLs") that will begin expiring in 2018. For federal income tax purposes, certain limitations are imposed on an entity's ability to utilize its NOLs in future periods if a change of control, as defined for federal income tax purposes, has occurred. In general terms, the limitation on utilization of NOLs and other tax attributes during any one year is determined by the value of an entity at the date of the change of control multiplied by the then-existing long-term, tax-exempt interest rate. The Internal Revenue Service has not yet addressed the manner of determining an entity's value. The Company has determined that, for federal income tax purposes, a change of control occurred during 2000. However, the Company does not believe such limitations will significantly impact its ability to utilize the NOLs.

Significant components of the provision for income taxes are as follows (in thousands):

Year Ended December 31,	2002	2001	2000
Current	$ (300)	$ 275	$ 25
Deferred	18,063	36,977	20,833
Income tax expense	$ 17,763	$ 37,252	$ 20,858

The differences between income tax expense and the amount that would be determined by applying the statutory federal income tax rate of 35% to the income before income taxes are as follows (in thousands):

Year Ended December 31,	2002	2001	2000
Federal income tax expense at statutory rates	$ 17,270	$ 36,217	$ 20,798
Non-deductible expenses and other	493	1,035	659
Valuation allowance	–	–	(599)
Income tax expense	$ 17,763	$ 37,252	$ 20,858

During 2000, the Company expected that it would realize all of its deferred tax assets and therefore decreased the valuation allowance to $0.

11. COMMITMENTS AND CONTINGENCIES:

The Company is, from time to time, party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position, results of operations or cash flows of the Company.

EMPLOYMENT CONTRACTS

The Company has employment contracts with certain of its executive officers. These contracts provide for annual base salaries, bonus compensation, various benefits and the continuation of salary and benefits for the respective terms of the agreements in the event of termination of employment for various reasons, and whether by the Company or the employee. These agreements are subject to automatic annual extensions unless terminated.

EMPLOYEE 401(K) RETIREMENT PLAN

In July 1998, the Company instituted a 401(k) retirement savings plan ("401(k) Plan") for its employees. The 401(k) Plan provides that all qualified employees may defer the maximum income allowed under current tax law. The 401(k) Plan covers all employees at least 21 years of age.

Effective January 1, 2000, the Company began matching employee contributions to the 401(k) Plan. The Company matches 100% of each participant's contributions up to 6% of the participant's annual base salary. In connection with the employer match, the Company issued 9,062 shares of Common Stock valued at $0.3 million in 2002, 5,456 shares of Common Stock valued at $0.2 million in 2001 and 5,923 shares of Common Stock valued at $0.1 million in 2000.

LEASES

The Company leases administrative offices under a non-cancelable operating lease expiring in 2007. The lease agreement requires that the Company pay for utilities, maintenance and other operational expenses of the building. Additionally, the lease contains escalation clauses. The Company also leases office equipment and oil and gas equipment under non-cancelable operating leases. Rental expense was $1.6 million, $0.7 million and $0.5 million in 2002, 2001 and 2000, respectively. Minimum future obligations under non-cancelable operating leases at December 31, 2002 for the following five years are $1.7 million, $1.3 million, $1.3 million, $1.2 million and $0.5 million, respectively.

SUMMARY OF CONTRACTUAL OBLIGATIONS

The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of December 31, 2002. The Company has incurred obligations in the ordinary course of business under purchase and service agreements that are not included in the table below, including obligations of approximately $35.4 million and $6.7 million in 2003 and 2004, respectively, for construction of the Green Canyon Blocks 338/339 ("Front Runner") spar production facility. Contractual obligations as of December 31, 2002 are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases	$ 6,032	$ 1,708	$ 3,800	$ 524	$ –
Other contractual obligations	–	–	–	–	–
Total	$ 6,032	$ 1,708	$ 3,800	$ 524	$ –

12. COMMODITY PRICE RISK MANAGEMENT ACTIVITIES:

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas.

In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. As of December 31, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003	60,000	$ 3.71	$ (5,979)
Second Quarter 2003	53,297	3.55	(4,411)
Third Quarter 2003	50,000	3.55	(4,068)
Fourth Quarter 2003	50,000	3.63	(4,340)
Year 2003	53,288	$ 3.61	$ (18,798)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor price and the fixed ceiling price. As of December 31, 2002, Spinnaker's commodity price risk management positions in natural gas collar arrangements and related fair value were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2003	15,000	$ 3.25	$ 5.21	$ (228)
Second Quarter 2003	15,000	3.25	5.21	(262)
Third Quarter 2003	15,000	3.25	5.21	(287)
Fourth Quarter 2003	15,000	3.25	5.21	(342)
Year 2003	15,000	$ 3.25	$ 5.21	$ (1,119)

The Company reported a net liability of $19.9 million and a net asset of $22.3 million related to its derivative contracts at December 31, 2002 and 2001, respectively. Amounts related to hedging activities as of December 31, 2002 and 2001 were as follows (in thousands):

As of December 31,	2002	2001
Current assets:		
Hedging asset	$ –	$ 20,593
Deferred income tax asset related to hedging activities	7,170	–
Non-current assets:		
Hedging asset	$ –	$ 1,726
Current liabilities:		
Hedging liability	$ 19,917	$ –
Deferred income tax liability related to hedging activities	–	7,208
Non-current liabilities:		
Deferred income tax liability related to hedging activities	$ –	$ 604
Accumulated other comprehensive income (loss):		
Accumulated other comprehensive income (loss)	$ (19,917)	$ 22,319
Income taxes	7,170	(7,812)
Accumulated other comprehensive income (loss)	$ (12,747)	$ 14,507

The Company recognized a net hedging gain of $4.7 million and net hedging losses of $9.6 million and $18.7 million in revenues in 2002, 2001 and 2000, respectively. There was no ineffective component of the derivatives recognized in earnings in 2002 and 2001. Based on future natural gas prices as of December 31, 2002, the Company would reclassify a net loss of $12.7 million from accumulated other comprehensive income (loss) to earnings within the next twelve months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

13. QUARTERLY FINANCIAL DATA (UNAUDITED):

Quarterly operating results for the years ended December 31, 2002 and 2001 are summarized as follows (in thousands, except per share amounts):

	(Unaudited) Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2002:				
Revenues	$ 32,600	$ 37,164	$ 51,558	$ 67,004
Income from operations	8,963	9,256	11,042	19,829
Net income	5,576	6,222	7,146	12,635
Net income per common share:				
Basic	$ 0.20	$ 0.19	$ 0.22	$ 0.38
Diluted	$ 0.20	$ 0.18	$ 0.21	$ 0.37
2001:				
Revenues	$ 67,453	$ 59,500	$ 44,818	$ 38,605
Income from operations	42,792	32,886	16,150	8,457
Net income	28,148	21,781	10,803	5,494
Net income per common share:				
Basic	$ 1.05	$ 0.80	$ 0.40	$ 0.20
Diluted	$ 1.00	$ 0.77	$ 0.38	$ 0.19

14. SUPPLEMENTARY FINANCIAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED):

CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES
(In thousands)

As of December 31,	2002	2001
Capitalized costs:		
Proved properties	$ 879,840	$ 575,806
Unproved properties not being amortized	141,326	102,881
Total	1,021,166	678,687
Accumulated depreciation, depletion and amortization[1]	(267,744)	(158,746)
Net capitalized costs	$ 753,422	$ 519,941

[1] Depreciation, depletion and amortization per Mcfe was $2.12, $1.60 and $1.57 in 2002, 2001 and 2000, respectively.

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES
(In thousands)

Year Ended December 31,	2002	2001	2000
Acquisition costs:			
Unproved	$ 39,789	$ 34,524	$ 21,421
Proved	–	–	–
Exploration costs	163,322	187,720	121,451
Development costs	139,368	80,276	51,144
Total costs incurred	$ 342,479	$ 302,520	$ 194,016

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines.

Costs being excluded from amortization consist of the following (in thousands):

Year Ended December 31,	Total	2002	2001	2000	1999 and Prior
Unproved property costs	$ 89,837	$ 28,635	$ 22,362	$ 4,910	$ 33,930
Exploration costs	49,751	11,306	(5,880)	37,559	6,766
Development costs	1,738	(1,496)	3,234	–	–
Total	$ 141,326	$ 38,445	$ 19,716	$ 42,469	$ 40,696

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES
(In thousands)

Year Ended December 31,	2002	2001	2000
Revenues	$ 188,326	$ 210,376	$ 121,383
Operating expenses[1]	18,212	12,132	9,009
Depreciation, depletion and amortization	108,998	85,059	47,451
Charges related to Enron bankruptcy	128	3,059	–
Income tax expense[2]	21,956	39,645	23,372
Results of operations	$ 39,032	$ 70,481	$ 41,551

(1) Operating expenses represent costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among other things, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation expenses.
(2) Income tax expense is calculated by applying the statutory tax rate to operating profit, then adjusting for any applicable permanent tax differences or tax credits and allowances.

Proved natural gas and oil reserve quantities and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P., independent petroleum consultants. Such estimates have been prepared in accordance with guidelines established by the Commission.

Proved reserves are estimated quantities of natural gas and oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

RESERVE QUANTITY INFORMATION

	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas Equivalents (MMcfe)
Proved reserves as of December 31, 1999	90,030	2,412	104,501
Extensions, discoveries and other additions	97,665	1,027	103,829
Revisions of previous estimates	5,248	(116)	4,552
Production	(28,845)	(225)	(30,194)
Proved reserves as of December 31, 2000	164,098	3,098	182,688
Extensions, discoveries and other additions	74,531	18,921	188,057
Revisions of previous estimates	(11,414)	2,829	5,556
Production	(51,234)	(310)	(53,094)
Proved reserves as of December 31, 2001 (1)	175,981	24,538	323,207
Extensions, discoveries and other additions	24,666	7,678	70,733
Revisions of previous estimates (2)	(11,936)	(1,168)	(18,944)
Production	(45,180)	(1,040)	(51,419)
Proved reserves as of December 31, 2002 (1)	143,531	30,008	323,577
Proved developed reserves:			
December 31, 2002 (1)	84,139	2,219	97,456
December 31, 2001 (1)	82,221	748	86,711
December 31, 2000	112,315	1,042	118,568
December 31, 1999	50,756	384	53,062

(1) Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery at Front Runner. This significant oil discovery changed Spinnaker's reserve profile. Proved oil and condensate reserves were 56% and 46% of total proved reserves at December 31, 2002 and 2001, respectively, compared to 10% at December 31, 2000. Of the Company's total proved reserves as of December 31, 2002, 70% were proved undeveloped reserves. Front Runner represented more than 60% of total proved undeveloped reserves.

(2) Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. As new reserves are added in the Front Runner area, changes in future production assumptions result in a reallocation of reserves subject to royalty relief. These reallocations resulted in downward revisions to previous estimates of approximately 671 MMcf and 1,002 MBbls, or natural gas equivalents of 6,681 MMcfe. No downward revision on any individual property exceeded 1% of proved reserves as of December 31, 2001.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

- Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.
- The estimated future gross revenues of proved reserves are priced on the basis of year-end market prices.
- The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates and the estimated effect of future income taxes.
- Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future natural gas and oil producing activities and tax carryforwards.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of the Company's natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment and the risks inherent in reserve estimates. Given the volatility of natural gas and oil prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if the Company has significant downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS
(In thousands)

Year Ended December 31,	2002	2001	2000
Future cash inflows[1]	$ 1,613,724	$ 944,861	$ 1,730,754
Future operating expenses	(185,782)	(164,105)	(60,259)
Future development costs	(184,441)	(191,711)	(68,929)
Future net cash flows before income taxes	1,243,501	589,045	1,601,566
Future income taxes	(259,436)	(120,489)	(516,488)
Future net cash flows	984,065	468,556	1,085,078
10% annual discount	(303,267)	(139,000)	(185,941)
Standardized measure of discounted future net cash flows	$ 680,798	$ 329,556	$ 899,137

[1] Prices for natural gas and oil used to calculate future cash inflows were $4.91, $2.71 and $9.99 per Mcf of natural gas and $30.50, $19.23 and $30.41 per barrel of oil as of December 31, 2002, 2001 and 2000, respectively.

PRINCIPAL SOURCES OF CHANGE IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

(In thousands)

Year Ended December 31,	2002	2001	2000
Standardized measure, beginning of year	$ 329,556	$ 899,137	$ 151,564
Extensions and discoveries, net of related costs	215,800	198,709	719,694
Sales of natural gas and oil produced, net of production costs	(165,450)	(207,824)	(131,030)
Net changes in prices and production costs	403,728	(958,755)	486,496
Change in future development costs	(26,795)	(18,959)	(3,501)
Development costs incurred during the period that reduced future development costs	56,831	47,463	37,851
Revisions of quantity estimates	(57,991)	6,092	34,749
Accretion of discount	(640)	132,067	15,156
Net change in income taxes	(80,892)	335,952	(421,535)
Change in production rates and other	6,651	(104,326)	9,693
Standardized measure, end of year	$ 680,798	$ 329,556	$ 899,137

Selected Financial Data

The following table sets forth some of the Company's historical consolidated financial data. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto included elsewhere herein. The selected consolidated financial data provided below are not necessarily indicative of the future results of operations or financial performance of the Company.

Year Ended December 31, (In thousands, except per share data)	2002	2001	2000	1999	1998
STATEMENT OF OPERATIONS DATA:					
Revenues	$ 188,326	$ 210,376	$ 121,383	$ 34,258	$ 3,298
Expenses:					
Lease operating expenses	18,212	12,132	9,009	5,411	474
Depreciation, depletion and amortization–natural gas and oil properties	108,998	85,059	47,451	20,788	2,738
Depreciation and amortization–other	914	398	309	213	437
Write-down of natural gas and oil properties (1)	–	–	–	–	2,642
General and administrative	10,984	9,443	7,350	4,860	3,809
Charges related to Enron bankruptcy (2)	128	3,059	–	–	–
Stock appreciation rights expense (3)	–	–	–	1,651	–
Total expenses	139,236	110,091	64,119	32,923	10,100
Income (loss) from operations	49,090	100,285	57,264	1,335	(6,802)
Other income (expense):					
Interest income	1,014	3,574	2,908	528	221
Interest expense, net	(762)	(381)	(748)	(2,805)	(279)
Total other income (expense)	252	3,193	2,160	(2,277)	(58)
Income (loss) before income taxes	49,342	103,478	59,424	(942)	(6,860)
Income tax expense	17,763	37,252	20,858	–	–
Income (loss) before cumulative effect of change in accounting principle	31,579	66,226	38,566	(942)	(6,860)
Cumulative effect of change in accounting principle (4)	–	–	–	(395)	–
Net income (loss)	31,579	66,226	38,566	(1,337)	(6,860)
Accrual of dividends on preferred stock	–	–	–	(7,911)	(7,094)
Net income (loss) available to common stockholders	$ 31,579	$ 66,226	$ 38,566	$ (9,248)	$ (13,954)
Basic income (loss) per common share (5) (6):					
Income (loss) before cumulative effect of change in accounting principle	$ 1.00	$ 2.45	$ 1.70	$ (1.06)	$ (3.44)
Cumulative effect of change in accounting principle (4)	–	–	–	(0.05)	–
Net income (loss) per common share	$ 1.00	$ 2.45	$ 1.70	$ (1.11)	$ (3.44)
Diluted income (loss) per common share (5) (6):					
Income (loss) before cumulative effect of change in accounting principle	$ 0.97	$ 2.34	$ 1.61	$ (1.06)	$ (3.44)
Cumulative effect of change in accounting principle (4)	–	–	–	(0.05)	–
Net income (loss) per common share	$ 0.97	$ 2.34	$ 1.61	$ (1.11)	$ (3.44)
Weighted average number of common shares outstanding (5) (6):					
Basic	31,695	27,079	22,679	8,355	4,059
Diluted	32,653	28,360	24,011	8,355	4,059
SUMMARY BALANCE SHEET DATA:					
Working capital (deficit)	$ (6,359)	$ (20,654)	$ 74,005	$ 19,675	$ (30,641)
Property and equipment, net	760,854	522,573	304,381	157,397	95,607
Total assets	842,715	587,316	442,704	189,553	102,769
Short-term debt	–	–	–	–	19,000
Accrued preferred dividends payable (6)	–	–	–	–	8,478
Total equity (6)	692,977	458,492	361,259	177,102	56,913

(1) At December 31, 1998, the Company recognized a non-cash write-down of natural gas and oil properties in the amount of approximately $2.6 million in connection with the ceiling limitation required by the full cost method of accounting for natural gas and oil properties. The write-down was primarily the result of the decline in natural gas prices experienced in 1998 and through April 9, 1999. As permitted by applicable Commission rules, in calculating the amount of the write-down, the Company used post year-end natural gas and oil price increases of $0.26 per MMBtu of natural gas and $4.52 per barrel of oil from December 31, 1998 to April 9, 1999. If the Company had used only December 31, 1998 natural gas and oil prices, it would have recognized a total non-cash write-down of natural gas and oil properties of approximately $13.0 million.

(2) The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million which were intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company has recorded a net reserve of $3.2 million against these receivables.

(3) Prior to July 1999, the stock option agreements of two of the Company's officers provided that they could elect to have Spinnaker deliver shares equal to the appreciation in the value of the stock over the option price in lieu of purchasing the amount of shares under option. Based on management's estimate of the share value of Spinnaker, the Company recorded compensation expense of approximately $1.7 million in 1999 related to the stock appreciation rights of the stock option agreements. In July 1999, these two officers agreed to eliminate the stock appreciation rights feature of their stock option agreements.

(4) The cumulative effect of change in accounting principle represents the adoption of Statement of Position 98-5 "Reporting on the Costs of Start-Up Activities."

(5) Spinnaker was originally formed as a limited liability company, and the Company issued common units and preferred units. In connection with its conversion to a corporation in January 1998, the Company exchanged Common Stock for all then outstanding common units and Preferred Stock for all then outstanding preferred units. The Company expresses all historical unit data in shares of Common Stock.

(6) On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock. In connection with its initial public offering in 1999, the Company issued 8,000,000 shares of Common Stock, converted all then outstanding shares of Preferred Stock into 6,061,840 shares of Common Stock and issued 1,200,248 shares of Common Stock to certain holders of the previously outstanding Preferred Stock in lieu of payment of accrued cash dividends.

Directors and Officers

BOARD OF DIRECTORS

ROGER L. JARVIS
Chairman of the Board, President
and Chief Executive Officer
Spinnaker Exploration Company

SHELDON R. ERIKSON (2) (3) *
Chairman of the Board, President
and Chief Executive Officer
Cooper Cameron Corporation

JEFFREY A. HARRIS (2) *
Member and Senior Managing Director / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

MICHAEL E. McMAHON (1) *
Executive Counsel to the Governor of the
State of Rhode Island and Providence Plantations on
Economic and Community Development
Rhode Island Economic Development Corporation

MICHAEL G. MORRIS (1) (3)
Chairman of the Board, President
and Chief Executive Officer
Northeast Utilities

HOWARD H. NEWMAN
Member and Vice Chairman / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

MICHAEL E. WILEY (1) (2)
Chairman of the Board, President
and Chief Executive Officer
Baker Hughes Incorporated

(1) Audit Committee
(2) Compensation Committee
(3) Nominating / Corporate Governance Committee
* Committee Chairman

CORPORATE OFFICERS

ROGER L. JARVIS
Chairman of the Board, President
and Chief Executive Officer

ROBERT M. SNELL
Vice President, Chief Financial Officer
and Secretary

WILLIAM D. HUBBARD
Vice President - Exploration

KELLY M. BARNES
Vice President - Land

L. SCOTT BROUSSARD
Vice President - Drilling and Production

JIMMY W. BENNETT
Vice President - Systems Technology and Processing

JEFFREY C. ZARUBA
Vice President, Treasurer and Assistant Secretary

SPINNAKER EXPLORATION COMPANY

Stockholder Information

CORPORATE ADDRESS

1200 Smith Street, Suite 800
Houston, Texas 77002
Phone (713) 759-1770
Fax (713) 759-1773
ske@spinexp.com
www.spinnakerexploration.com

TRANSFER AGENT

Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden, Colorado 80401
(303) 262-0600

OUTSIDE LEGAL COUNSEL

Vinson & Elkins L.L.P.
Houston, Texas

INDEPENDENT AUDITORS

KPMG LLP
Houston, Texas

FORM 10-K AND OTHER REPORTS

Spinnaker files reports with the Securities and Exchange Commission ("Commission") on Forms 10-K, 10-Q and 8-K. The public may read and copy any materials that the Company files with the Commission at the Commission's public reference room. The public may also access Spinnaker's annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished to the Commission pursuant to Section 13(a) or 15(d) of the Exchange Act on its internet website at www.spinnakerexploration.com, free of charge, as soon as reasonably practicable after Spinnaker electronically files or furnishes such material with or to the Commission.

MARKET INFORMATION

Spinnaker's common stock trades on the New York Stock Exchange under the symbol "SKE." The following table sets forth the range of high and low sales prices per share of common stock for each calendar quarter.

	Sales Price	
	High	Low
2001:		
First Quarter	$ 44.50	$ 33.00
Second Quarter	$ 48.00	$ 36.60
Third Quarter	$ 43.96	$ 30.00
Fourth Quarter	$ 45.55	$ 33.30
2002:		
First Quarter	$ 44.64	$ 34.45
Second Quarter	$ 44.89	$ 35.77
Third Quarter	$ 36.90	$ 24.46
Fourth Quarter	$ 29.71	$ 18.45
2003:		
First Quarter (through March 25, 2003)	$ 22.70	$ 17.15

As of March 25, 2003, there were 39 holders of record of the Company's common stock.

ANNUAL MEETING

The Company's annual meeting of stockholders will be held at 9:00 a.m. on Tuesday, May 6, 2003, at the DoubleTree Hotel at Allen Center, 400 Dallas Street at Bagby, Houston, Texas.

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